

THE COST OF EQUITY CAPITAL IN A REGULATORY ENVIRONMENT: AN INTERNATIONAL COMPARISON

by

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DISSERTATION

Submitted in partial completion for the

MASTER OF COMMERCE

Financial Management

UNIVERSITY OF CAPE TOWN

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Abstract

South Africa's electricity tariff determinations have been a matter of much public debate. This has been highlighted in popular media in South Africa, with above inflation increases in electricity tariffs allowed by the National Energy Regulator of South Africa (NERSA) in Multi-Year Price Determination (MYPD) 2 and MYPD 3. However these increases are below those applied for by Eskom. Estimating the cost of equity capital is a key element of the tariff determination process. This study therefore aims to evaluate the cost of equity methodologies used by regulators, and to assess whether NERSA's (South Africa) methodology is in line with international best practice. This study analysed the published cost of equity methodologies of 14 electricity regulators operating within developed and developing economies. A review of academic literature indicates that the Capital Asset Pricing Model (CAPM) understates the returns of low beta stocks, such as utilities. Furthermore, the Fama and French Three Factor model (FF3F) has been shown to have better explanatory power and results in higher estimates of the cost of equity. In spite of these empirical findings, this study found a preference for the CAPM among regulators, with no regulators using the FF3F model. The CAPM is selected due to its widespread use and the fact that it is simple to implement. This finding indicates that regulators are systemically under-compensating utilities for the risk undertaken. NERSA's (South Africa) cost of equity methodology was found to be in line with regulatory methodology, although its lack of consideration of alternatives and its relative lack of disclosure into the estimation does result in less transparency and potentially less reliable estimates of the cost of equity. Until a definitive answer has been reached, it is likely that the CAPM will continue to be used in a regulatory environment.

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1. Introduction

1.1. What is regulation?

Due to economies of scale, certain industries are naturally biased to result in monopolies. In an unregulated environment, these firms will be able to set prices in order to maximise their profits. Therefore regulation of these industries is necessary in order to avoid the duplication of unnecessary facilities and the windfall profits that would be earned by the firms (Demsetz, 1968). The regulated firms would, by nature, tend to operate in industries which are structurally important to the economy as a whole. Therefore, the regulator would need to strike a careful balance between protecting the interests of the consumers, and ensuring that the firm earns sufficient return in order to continue investing in vital infrastructure (Stigler, 1971).

1.2. Why is the study of regulatory pricing so important for South Africa?

In South Africa, the National Energy Regulator of South Africa (NERSA) is charged with regulating the energy markets, including Eskom. NERSA (South Africa) and its pricing determinations of Eskom have been a matter of much debate in popular media.

South Africa has historically had some of the lowest cost electricity in the world, which benefitted its energy intensive economy, driven by industries such as mining. The real cost of electricity actually declined between 1983 and 2008 as Eskom did not invest in its infrastructure over this period, resulting in ageing power stations being used (Gresty, 2010). This culminated in significant power shortages in South Africa in 2008 as the infrastructure was not sufficient to handle the demand (Erero, 2010).

In response to this electricity crisis, Eskom embarked on a large investment programme which is still underway. In order to ensure its prices were reflective of the costs of generation, NERSA (South Africa) has been allowing Eskom price increases significantly above inflation in the MYPD2 and MYPD3¹ determinations (Gresty, 2010; National Energy Regulator of South Africa, 2013).

¹ MYPD2 and MYPD3 refer to Eskom's Multi-Year Pricing Determinations. This is the process NERSA uses to determine electricity prices over a number of years. MYPD2 applied for the three year period ending on 31 March 2013. MYPD3 applies for five years from 1 April 2013 until 31 March 2018.

However, the allowed increases have consistently been below the increases applied for by Eskom. Eskom applied for a 45% price increase in its MYPD2 determination, and was allowed a 25% price increase (Gresty, 2010). Eskom applied for a 16% price increase in its MYPD3 determination and was only allowed an 8% increase (National Energy Regulator of South Africa, 2013). Eskom's annual financial results show a revenue shortfall of R225 billion created by the MYPD3 determination, and a return on assets of -0.53% compared to the cost of capital used in MYPD3 of 3.8% (Eskom, 2014). This would indicate that Eskom is not earning sufficient returns on its capital, which may affect investment or maintenance of the infrastructure.

At the current rate of price increases, Eskom will only reach cost reflective tariffs in 2017/18. Eskom is now under significant pricing pressure, and may be subject to a further downgrade of its credit rating, effectively putting a stop to Eskom's capacity expansion programme. Eskom is therefore requesting that government reopen the tariff determination process. It is anticipated that should the tariff increase from the 8% allowed to the 16% required by Eskom, this will result in an increase in the inflation estimates by 0.8% (Masia, 2014).

1.3. How does the cost of capital affect regulatory pricing?

NERSA (South Africa) determines the allowed revenue for Eskom based on a defined formula over the MYPD period. The methodology states that "the revenue to be earned by Eskom should be equal to the efficient cost to supply electricity plus a fair return on the rate base" (National Energy Regulator of South Africa, 2012). The formula therefore includes measures of the efficient cost of operating, and an allowance to earn a return on its regulatory asset base² (RAB). NERSA (South Africa) uses the following formula to determine this allowed revenue:

Allowed Revenue = **Return on RAB** and working capital + opex costs + depreciation + charges (network costs, losses & ancillary charges) + Allowances for service incentives +/- Risk management adjustments

Each of the above factors in the calculation have their own estimation uncertainties, however the focus of this study is on the return on RAB. NERSA's (South Africa) MYPD methodology requires that the return on the RAB be a function of the replacement value of the regulatory asset base, multiplied by the real weighted average cost of capital (WACC) of Eskom (National Energy Regulator of South Africa, 2012).

² The RAB includes all of the assets used by Eskom in the production and supply of electricity (National Energy Regulator of South Africa, 2012).

Given that in the MYPD3 determination, Eskom's RAB for the 2013/14 year was R699 609 million (National Energy Regulator of South Africa, 2013), a 1% increase in the weighted average cost of capital will result in a 4.3% increase in the allowed revenue for Eskom for the year.

The calculation of the weighted average cost of capital has a number of inputs including the cost of debt, capital structure, cost of preferred shares, corporate and personal taxes and the cost of equity (Sudarsanam, Kaltenbronn, & Park, 2011). This study focusses on the determination of the cost of equity as it is one of the most difficult issues in the determination process, given the lack of consensus on its determination (Jenkinson, 2006, pg. 146-163).

The cost of equity is therefore a key determinant of Eskom's required revenue. If NERSA's (South Africa) estimate of the cost of equity is not in line with international best practice, empirical evidence and academic theory, it may be under- or over-compensating Eskom in its tariff increases.

1.4. Research questions and objectives of this study

Therefore, considering the importance of the cost of equity, and the debate over its determination in a regulatory environment, this study aims to evaluate the methodologies employed to estimate the cost of equity by regulators. The study will focus on the regulatory methodologies of electricity regulators (including NERSA (South Africa)) given its importance in the South African market. The research questions of this study and objectives are discussed below:

Research question 1: How is the cost of equity estimated in a regulatory environment?

Objective 1: To evaluate whether there is consensus among regulators as to the methodology to estimate the cost of equity (including the model and its determinants)

Objective 2: To consider whether the methodologies used by regulators are consistent with theory and empirical findings.

Research question 2: Is NERSA's (South Africa) cost of equity methodology consistent with international practice?

Objective 3: To assess whether NERSA's (South Africa) methodology is consistent with applicable theory, empirical evidence and international best practice and therefore is appropriately compensating Eskom in its regulatory determinations.

This study aims to add to existing knowledge on the regulatory cost of capital by performing a consolidated review of the academic literature on the cost of capital in a regulatory environment in order to assess whether the theory and empirical evidence indicates a model which is preferable to use in regulated electricity companies.

The study will perform a survey of electricity regulators' methodologies, including the selection of the cost of equity model and its determinants. The aim is to evaluate whether international practice indicates which cost of equity model is most appropriate to use in a regulatory environment. Also, the study aims to assess whether NERSA's (South Africa) cost of equity methodology is in line with international best practice. Eskom has not received the tariff increases from NERSA (South Africa) which it applied in MYPD 3. Should the increases not appropriately compensate Eskom, it may result in a lack of investment in a key structural industry which will affect economic growth of the country. However, consumers are directly affected by the impact of electricity increases. An additional 8% increase in the tariffs will increase South African inflation by 0.8% (Masia, 2014).

1.5. Outline

This study will be divided into three parts. Chapter 2 will perform a review of appropriate literature regarding the cost of equity capital with a particular focus on its use in a regulatory environment. Chapter 3 will detail the research methodology adopted, including the selection of data. Chapter 4 includes the results of the regulatory survey and the analysis of the information collected. Finally, Chapter 5 will present a summary of the research findings and provide a conclusion on the study, including identifying areas for future research.

2. Literature Review

2.1. Methods of calculating the cost of equity

As this study focusses on a limited area of application of the cost of equity, it is necessary to consider the key requirements for models used in regulatory decisions. This will therefore create a context from which to evaluate the models presented. Aharonian, Villadsen and Vilbert (2010) present eight requirements for a cost of equity model in regulation: the model must 1) be consistent with the aim of the regulation, 2) be transparent, 3) minimise the use of judgemental factors, 4) produce consistent results, 5) be robust to small variations in the sampling error, 6) be as simple as possible while maintaining reliability, 7) be able to be replicated by others and, 8) recognise the regulatory context and legislation in which the regulatory body operates. These are consistent with requirements considered by regulators themselves (see Appendix A) (Australian Energy Regulator, 2013a).

With this context in mind, Brigham, Shome and Vinson (1985), Sudarsanam, Kaltenbronn and Park (2011) and Aharonian, Villadsen and Vilbert (2010) note that there are a number of methodologies which may be employed in estimating the cost of equity in a regulatory environment. These are comparable earnings method, the discounted cash flow (DCF) method, risk premium method and the Capital Asset Pricing Model (CAPM) and CAPM derivative and the Residual Income method. An evaluation of these methodologies follows.

2.2. Comparable Earnings method

The comparable earnings method of calculating cost of equity capital was widely used in American regulatory decisions in the 1970s and before. Copeland Jr. (1978) noted that in 1978 more than half of the state commissions in the US relied upon or accepted the comparable earnings as a method for determining the cost of equity. This was due to the fact that this model was in line with the wording included in applicable American case law (Aharonian, Villadsen, & Vilbert, 2010; Copeland Jr., 1978).

This is an accounting based method that involves selecting a sample of unregulated companies deemed to be comparable to the regulated entity and whose investment risk is judged to be equivalent to the firm under question (Aharonian et al., 2010). The average return on equity (ROE) of this sample of companies is calculated and the regulated companies rates are set to allow it to earn the same level of ROE (Brigham, Shome, & Vinson, 1985). A number of different comparable earnings measures could be used, including market to book ratios, dividend to price ratios and price to earnings ratios (Gelhaus & Wilson, 1968; Thatcher, 1954).

The comparable earnings method is a model that is easy for regulators to implement as the data is generally easily accessible and, if implemented correctly, it is transparent. Sudarsanam, Kaltenbronn and Park (2011) note that the model meets the requirements in the US and Canada of providing a fair return equal to the return on comparable risk investments. Furthermore, if the regulatory formula uses the book value of the investments to calculate the allowed return, the use of the comparable earnings method will result in a consistent basis for the decision (Sudarsanam et al., 2011).

Gözen (2011) notes a number of disadvantages with the comparable earnings model. These are that the cost of equity is determined by using earnings based on book values while the concept cost of capital is a market-oriented. It is difficult to find comparable companies due to the fact that no two companies are identical even if they have the same shareholder structure and are in the same business. Also, this method is particularly difficult to apply in emerging markets. Price to earnings ratios may change continuously and therefore it may be difficult to determine the ratio to be used for a developing market utility. Also, the method requires the assumption of efficient markets which may not exist in developing markets (Gözen, 2011).

Sudarsanam, Kaltenbronn and Park (2011) noted further disadvantages with the model including that the methodology is based on historical accounting returns and therefore does not take future conditions into account. Furthermore, the use of accounting data may result in a lag. As a result, the regulatory decision may not be based on recent and relevant information. Accounting information is subject to the different accounting policies which have been applied by the comparator companies and so may not reflect changes in the market conditions. As a result it may not be reflective of the true cost of capital (Sudarsanam et al., 2011).

Furthermore, the comparable firms used may be earning returns below the cost of equity. In this case, using this as a basis for the cost of equity capital would result in lower investment due to the value destruction (Copeland Jr., 1978). Due to the problems associated with the model, it is not an appropriate method to use it to determine the cost of equity capital in regulation ((Brigham et al., 1985; Copeland Jr., 1978)

2.3. The Risk Premium approach

The risk premium approach to calculating the cost of equity is based on a risk return trade-off similar to the CAPM. Aharonian, Villadsen and Vilbert (2010) name it a simplified version of the CAPM. The risk premium approach involves adjusting the cost of debt by a risk premium as follows:

$$k_e = k_d + \text{estimated risk premium}$$

Where k_e is the cost of equity and k_d is the cost of debt.

This model is simple to implement due to the fact that it only requires two inputs. Sudarsanam, Kaltenbronn and Park (2011) note that although the model is based on a risk return trade-off which is similar to the CAPM, it lacks the theoretical foundations as it is not based on an equilibrium relationship between risk and return. Conine Jr. and Tamarkin (1985b) note that a theoretically correct method is more defensible than an ad hoc method. Refer to 2.9.1 below for a more thorough discussion of the methods involved in estimating risk premiums. As this study focusses on the cost of equity, the calculation of the cost of debt is out of its scope and as a result the literature relating thereto has not been evaluated.

2.4. Discounted Cash Flow (DCF) method

The discounted cash flow method of calculating the cost of equity capital is based on the dividend discount model as developed by Gordon (1962). This method was the most widely used methodology by regulators in the US (Copeland Jr., 1978; Ketchum & Kim, 2013; Sudarsanam et al., 2011). Gordon's model is a share valuation model whereby the value of the share is a function of the discounted value of all expected future dividends (Gordon, 1962). The Gordon growth model takes the form:

$$P_0 = \frac{(D_1)}{(k_e - g)}$$

Where P_0 is the price of a share at time $t = 0$, D_1 is the dividend at time $t = 1$ and g is the expected constant growth rate in dividends.

Rearranging the formula, we find that the cost of equity is:

$$k_e = \frac{D_1}{P_0} + g$$

D_1 can be measured as a function of the current (most recent) dividend paid as $D_1 = D_0(1 + g)$. The cost of equity capital is therefore a function of the dividend yield on the firm and the expected future growth of the dividend. Damodaran (2002) notes that the future growth in earnings can be substituted into the calculation. This is due to the fact that all other measures of the firm's performance would be expected to grow at the same rate. If the dividend grew by more than earnings, it would exceed earnings over time. This is linked to the fact that the model assumes that the dividend pay-out ratio and capital structure stay constant over time (Damodaran, 2002; Gordon & Gould, 1977).

This model has a number of drawbacks which limit its applicability. It cannot be used when a firm does not pay dividends. Furthermore, it cannot be used for valuation purposes where $g > k$ and it requires projecting a constant growth rate over an infinitely long horizon. Furthermore, in practice the company to which it is applied needs to be listed due to the requirement to discount the future dividends to the current share price (Malkiel, 1970).

A problem that has been identified with this model, is the use of a constant growth rate (Damodaran, 2002; Heaton & Lucas, 2000; Malkiel, 1970; Sudarsanam et al., 2011). This assumption is noted as not being realistic in practice, and the growth rate calculated cannot be greater than the growth rate of the economy as a whole in perpetuity (Damodaran, 2002). This can be adjusted by the use of a two stage model, where dividends are assumed to grow initially at a faster rate and then the growth declines to a stable long term growth rate (such as the long term growth rate of the industry as a whole) (Heaton & Lucas, 2000; Malkiel, 1970). This two-stage model is as follows:

$$P_0 = \sum_{t=1}^T \frac{D_t}{(1+k)^t} + \frac{D_T(1+g)}{[(1+k)^T(k-g)]}$$

This model may be extended further to assume a third stage, whereby the growth is initially at a high rate, and then declines over time to a constant growth rate (Damodaran, 2002; Sudarsanam et al., 2011).

The DCF method is theoretically sound and it is also simple to use by regulators. Furthermore, the DCF is best used by companies which are growing at a rate comparable or lower to the growth in the economy and have well documented dividend policies which are expected to continue into the future (Damodaran, 2002). Based on the nature of regulated entities, they therefore fit well into these criteria due to their reliance on the general economy for growth and the stability provided by regulation. Graham and Harvey (2001) found that few firms use the dividend discount model.

However, a major difficulty still arises in the use of the model in terms of making reliable and unbiased estimates of future dividends, the timing thereof and their growth pattern (Sudarsanam et al., 2011). A number of problems have been identified relating to the DCF model in regulation. Linke and Zumwalt (1984) showed that the DCF models that are commonly used in rate of return regulation result in biased estimates of the cost of equity capital. The bias results from the fact that the model used in rate of return determinations does not treat the timing of dividends correctly. Also, a market determined rate needs to be adjusted to be used in rate of return regulation (Linke & Zumwalt, 1984).

2.4.1. Methods of calculating g

The growth rate used in the formula for calculating the DCF cost of equity can have a material impact on the result. Damodaran (2002) notes that as the growth rate converges to the cost of equity, the value of a firm goes to infinity. As a result, the estimation of g is a key factor in the use of the DCF model, especially for regulatory purposes. The growth rate used in the DCF can be calculated using growth rates constructed from historical data or those based on security analysts' future forecasts (Malkiel, 1970).

2.4.1.1. Historical data

The use of historical data to estimate the growth for the DCF model is based on the assumption that historical performance is an accurate forecaster of future performance. A number of different proxies have been used in the literature as the measure of g in the DCF model. However, historical growth rates differ based on the period of the calculation, the method of the calculation as well as the accounting data on which the calculation is based (Malkiel, 1970).

A commonly used measure for g is the sustainable growth rate, i.e. $g = ROE(1-p)$ where ROE is return on equity and p is the proportion of earnings reinvested (Damodaran, 2002; Heaton & Lucas, 2000). Other measures used for growth rates are total dividends paid per share, end of year market prices and reported earnings per share. Malkiel (1970) found that out of forty measures, the ten-year growth rate of cash earnings per share (being the normalised earnings plus depreciation and amortization), calculated as a geometric mean of the ratios was clearly superior. Time series proxies for growth may be less accurate than market expectations as they take into account a smaller set of information as well as being lagged estimators (Keane & Runkle, 1998).

2.4.1.2. Expectational estimates of growth rates

The other method used to calculate the growth rate is the use of forecasts of growth. Expectational forecasts result in a much better fit than historical estimates (Malkiel, 1970). Sudarsanam, Kaltenbronn and Park (2011) note that regulators have relied on analysts' forecasts as these are observable measures of the market's expectations of future growth.

Benefits to using analysts' estimations of future growth are that they are not limited to published data as they frequently visit management and discuss the firm's prospects with them. Economic theory would suggest that the continued employment of analysts' by profit maximising firms implies that the analysts' estimates are more accurate than less costly time series estimates (Malkiel, 1970).

Initial studies have found that the estimates of security analysts proved little better as estimators of future growth than did mechanical or naïve estimates using historic growth rates (Cragg & Malkiel, 1968; Elton & Gruber, 1972). Furthermore, Elton and Gruber (1972) found significant differences in the accuracy of the mechanical models with the earnings-smoothing model found to be the most accurate, although the time span of the forecast does affect which model produces the best forecast. Cragg and Malkiel (1968) did note that care should be taken in interpreting their results as they may be atypical and only a few firms were able to participate in the study. The findings of these two studies do suffer from deficiencies, which weaken their results (Brown & Rozeff, 1978). This is due to the fact that these studies were performed over short periods, and due to the number of naïve models used, it is possible that the outperformance of the naïve models was just by chance (Givoly & Lakonishok, 1984).

Brown and Rozeff (1978) compared the performance of Value Line³ forecasts for annual periods and up to five quarterly forecasts. They found that the Value Line forecasts provide significantly better forecasts than do naïve time-series models. These findings have been replicated in a number of other studies (Capstaff, Paudyal, & Rees, 2001; Chatfield, Moyer, & Sisneros, 1989; Conroy & Harris, 1987; Keane & Runkle, 1998; Richards, Benjamin, & Strawser, 1977). This superiority was found over all time horizons, however a tendency for the superiority to decline as the horizon lengthened (Brown & Rozeff, 1978; Capstaff et al., 2001; Conroy & Harris, 1987).

Furthermore, the accuracy of analysts' forecast tends to increase as the number of analysts increases (Conroy & Harris, 1987; Givoly & Lakonishok, 1984). Analysts' forecasts are not as accurate at the beginning of the financial year (Conroy & Harris, 1987; Elton, Gruber, & Gultekin, 1984) and the analyst's forecast errors decline as the end of the financial year approaches (Elton et al., 1984). Rozeff and Brown (1978) provide an explanation for this by stating that during the period between the most recent earnings announcement and the prediction, the analysts obtain additional information. The information is likely to be the most important for predicting the future quarter's earnings. Analysts' forecasts are also more likely to be inaccurate and more optimistic the greater the international diversification of the firm (Duru & Reeb, 2002).

³ Value Line is an independent investment research and financial publishing firm (Money-Zine, 2014)

The sector in which the stock operates may have an impact on the accuracy of the forecasts. Forecast errors and forecast optimism increase with stock return volatility (Beckers, Stelias, & Thomson, 2004). Beckers et al. (2004) found that earnings forecasts for public utilities were significantly more correct compared to other sectors, particularly as the forecast horizon lengthened. Richards et al. (1977) found that analysts' forecasts for electric utilities were among the most accurate, after banking and drug companies.

Kean and Runkle (1998) found that analysts make rational and unbiased forecasts of future earnings. Discretionary special charges (such as asset write downs) may lead one to conclude that forecasts are upward-biased as analysts do not forecast based on these charges (Keane & Runkle, 1998).

In contrast, other studies have found that analysts do provide biased earnings estimates. A number of studies have identified an optimism bias in analysts' forecasts. Analysts tend to overreact to positive information and underreact to negative information (Capstaff et al., 2001; Easterwood & Nutt, 1999; Kadous, Krische, & Sedor, 2006; Marsden, Veeraraghavan, & Ye, 2008; Sedor, 2002). Furthermore, Ke and Yu (2006) found that analysts initially issue optimistic earnings forecasts in order to please management and then downgrade to negative forecasts prior to earnings announcements. These estimates were found to be more accurate and the analysts were less likely to be fired. This is consistent with the hypothesis that analysts use biased earnings estimates in order to gain favour with management in order to gain better access to managements' private information (Ke & Yu, 2006). Forecast errors can be ascribed to the "objectivity illusion", where information is processed in a manner that supports one's goal, and the "trade boosting" hypothesis, where forecasts are biased by the incentive to boost trade (Eames, Glover, & Kennedy, 2002). Eames et al. (2002) find that analysts' forecast errors are significantly optimistic for buy recommendations and significantly pessimistic for sell recommendations. Their findings are more consistent with the objectivity illusion.

2.5. Residual Income model

The residual income (RI) model is closely linked to the DCF model, as it calculates the cost of equity based on the expected income of the firm. The RI model is derived from the DCF model under the clean surplus relationship (Ohlson, 1995). This is the assumption that the changes in a firm's retained earnings are only due to retained earnings. This clean surplus relationship does not hold as IFRS allows for changes in capital that are not accounted for on market terms and, on a per share basis, where there are expected changes in shares outstanding (Isidro, Hanlon, & Young, 2006; Ohlson, 2000, 2001)

In the residual income model:

$$Equity\ Value = E_{BV0} + \sum_{t=1}^t \frac{(NI_t - k_e \times E_{BV_{t-1}})}{(1 + k_e)}$$

Where E_{BV0} is the book value of equity at time 0, NI_t is the firms net income at time $t = 1, 2, 3, \dots$ and k_e is the cost of equity capital (Sudarsanam et al., 2011). The term $NI_t - k_e \times E_{BV0}$ is the expected residual income in years $t = 1, 2, 3$. This therefore represents the excess of the net income over the Rand cost of using the Assets E_{BV0} at the firm's cost of equity during period t . This can be rearranged to make k_e the subject of the formula. The Residual Income model forms the based of the EVA™ Model as used by Stern Stewart and the Economic Profit Model used by McKinsey & Company (Correia, C (2014), pers. comm, 21 June).

This model has a number of benefits over the DCF model. It can be used irrespective of whether the firm pays dividends and it also relates both earnings and assets to the market value of equity as opposed to just dividends. As dividend forecasts rely on earnings estimates, the reliance of the RI model on earnings makes it a simpler model. Also, the DCF models are very sensitive to the terminal value, whereas the RI model front end loads this value in the book value of equity (Sudarsanam et al., 2011). However, as analysts' forecasts tend to be for a limited short-term period, the RI model is usually adjusted to discount the short term RI and then calculate a terminal value based on an assumed terminal growth rate, usually that of the industry or market (Sudarsanam et al., 2011).

The RI model is subject to a lack of availability of long term forecasts, the need to assume a terminal growth rate as a result of such non-availability and the optimism bias implicit in analysts' forecasts (Sudarsanam et al., 2011). Furthermore, this model cannot be used if there are no forecasts of earnings.

2.6. Capital Asset Pricing Model (CAPM)

The CAPM is widely used in practice. Graham and Harvey (2001) found that CAPM is the most popular method used in estimating the cost of equity, with average stock returns being second and multi-beta CAPM's being third. Bruner et al. (1998) found that the CAPM is the dominant model used in practice (Bruner, Eades, Harris, & Higgins, 1998). In South Africa, the CAPM has also been found to be the dominant model used in practice (Correia & Cramer, 2008; PriceWaterhouseCoopers Corporate Finance, 2012). Schaeffler and Weber (2011) found that all of the 21 regulators sampled used the CAPM, with only one considering the DCF model in addition. Further studies on the cost of equity model used in a regulatory environment suggests that the CAPM is favoured by regulators (Buckland & Fraser, 2001; D. Miles, Wright, & Mason, 2003; R. W. Roll & Ross, 1983; Sudarsanam et al., 2011)

2.6.1. The traditional version of the CAPM

The CAPM was developed by Sharpe (1964), Lintner (1965) and Mossin (1966) and marks the birth of modern asset pricing theory (Fama & French, 2004). It is based on the premise that in equilibrium there will be a simple linear relationship between the expected return of an efficient combination of risky assets and its standard deviation of return, i.e. the return that investors require is a function of the riskiness of the asset. The traditional version of the CAPM is as follows:

$$k_e = R_f + \beta (R_m - R_f)$$

Where k_e is the cost of equity capital, R_f is the risk free rate, β is the measure of the systematic risk of the stock and R_m is the market return (Lintner, 1965; Mossin, 1966; Sharpe, 1964).

The CAPM was developed under a strict set of assumptions; 1) investors are risk averse and have homogenous beliefs, 2) riskless assets exist, 3) all assets are marketable, 4) there are no transaction costs or indivisibilities, 5) all investors can borrow and lend at the risk free rate (Black, Jensen, & Scholes, 1972; Black, 1972; Damodaran, 2002; Fama & French, 2004).

Furthermore, as it is based on the Markowitz (1952) model, it is a one period model which assumes that the portfolio is rebalanced at the end of each period (Sudarsanam et al., 2011). Also, the risk and return relationship of the CAPM is based on the premise that the beta captures all market risk (Damodaran, 2002). The CAPM has been widely criticised due to these simplifying assumptions. However, the model should be considered in terms of its practical outcomes as opposed to its theoretical underpinnings (Conine Jr. & Tamarkin, 1985b; Sharpe, 1964).

Numerous studies have been performed to test the CAPM empirically. Fama and Macbeth (1973) tested the hypotheses of the CAPM, including that no measure of risk, other than β , systematically affects the expected returns, that the relationship between expected return and β is linear and that a positive trade-off between risk and return exists. They were unable to reject these hypotheses, and therefore could not refute the CAPM (Fama & Macbeth, 1973).

Jensen, Black and Scholes (1972) found that the expected return on an asset is not directly proportional to its beta. They find that this evidence is strong enough to reject the traditional CAPM. Their findings indicated that high-beta stocks have negative α 's and low beta stocks have positive α 's. As a result, the expected excess return on a low (high) beta asset is higher (lower) than the CAPM suggests. Other empirical studies have found the same relationship (Fama & French, 2004; Friend & Blume, 1970). Fama and French (2004) found that while there was a positive linear relationship between the beta and the average return, the relationship was "flatter" than that estimated by the CAPM. As regulated companies tend to have low betas, these findings would indicate that the traditional CAPM would understate the required return for the regulated firm. An inappropriate return would result in less incentive to invest in key structural industries.

Roll's (1977) critique of these empirical tests of the CAPM was based on the fact that the market portfolio of the CAPM must contain all individual assets, including traded and non-traded assets. However, in practice a proxy must be used to test the theory. As a result, any proxy used may be mean variance efficient when the true market portfolio is not and visa-versa (Roll, 1977). Roll (1977) notes that most reasonable proxies will be highly correlated with other proxies and the market portfolio irrespective of whether they are efficient. This may make it appear as if the actual composition is unimportant and may result in inappropriate inferences (Roll, 1977).

The assumption of unlimited borrowing and lending at the risk free rate is unrealistic and may result in the Jensen, Black and Scholes (1972) findings. Black (1972) developed a model without risk-free borrowing and lending. Black (1972) showed that the CAPM's relationship can still be obtained by allowing unlimited short sales of risky assets. This model is named the Black CAPM. Fama and French (2004) argue that this is also an unrealistic assumption.

Litzenberger et al. (1980) stated that the version of the CAPM that should be used in estimating a public utility's cost of capital cannot be demonstrated by theoretical arguments. They also contend that evidence presented in the literature is consistent with CAPMs that have released the restrictive assumptions of the CAPM, and allow for risky assets not included in the NYSE stock index, taxes and skewness⁴ preference (Ramaswamy, Sosin, & Litzenberger, 1980).

⁴ Refer to Section 2.8.3 for a fuller discussion of skewness.

Litzenberger et al. (1980) assert that if risk premiums are proportional to NYSE betas, it will result in a downward (upward) biased cost of equity for public utilities with a NYSE beta that is less (greater) than one, a dividend yield higher (lower) than the yield on the value weighted NYSE stock index and systematic skewness that exceeds (is less than) its beta.

The CAPM predicts that the intercept is the risk free rate, i.e. that for a stock that is independent of the variations in the market, the return will be the risk free rate. Empirical tests have found that the intercept is greater than the risk free rate (Black et al., 1972; Fama & French, 1992; Fama & Macbeth, 1973; Friend & Blume, 1970).

A number of research studies were performed from the 1970s onwards which have identified anomalies within market returns. These anomalies are firm characteristics that provide explanatory power to the cross section of stock returns beyond those of the CAPM's beta. Although this is not a comprehensive list, and the literature regarding market inefficiency will not be discussed in this paper as it is beyond its scope, it does provide evidence as to practical problems with the CAPM. These anomalies include:

Neglected Firm Effect: Arbel, Carvel and Strebel (1983) note that there are a large number of shares which are unsuitable to institutional investors, and as a result receive minimal analyst coverage (hence "neglected firms"). Arbel, Carvel and Strebel (1983) found that the returns on these shares were found to significantly outperform the returns on securities that are widely held by institutions (Arbel, Carvel, & Strebel, 1983).

The Weekend Effect: Average returns on stocks on Mondays were significantly negative, whereas they were positive for all of the other weekdays (French, 1980).

January effect: The return on stocks in January in the US is generally higher than in any other month. This appears to relate to tax loss selling (Gultekin & Gultekin, 1983; Keim, 1983; Reinganum, 1983; Rozeff & Kinney Jr., 1976).

Smaller firm effect: Smaller firms tend to provide abnormal returns compared to those predicted by the CAPM. This effect is more pronounced in January (Banz, 1981; Keim, 1983; Reinganum, 1983; Roll, 1983).

Monthly effect: Stock returns appear to earn positive returns around the beginning and during the first half of the month and are zero during the second half of the month (Ariel, 1987).

Market overreaction: Empirical evidence suggests that people tend to overreact to unexpected and dramatic news events. This overreaction hypothesis was found to occur in the behaviour of stock market returns (De Bondt & Thaler, 1985).

2.6.2. CAPM use in regulation

Brigham and Crum (1977) find that there are a number of problems with the CAPM for it to be used in regulation, including: 1) it is based on a number of unrealistic assumptions, 2) there is disagreement over the most appropriate rate to use as the risk free rate, 3) the equity risk premium cannot be measured with precision and 4) not only is the beta coefficient unstable, but it is unknown how to measure the future beta coefficient of a stock, which is the appropriate value for the CAPM and 5) the beta coefficient of a stock can actually decrease as a result of an increase in systematic risk.

Breen and Lerner (1972) find that the cost of equity estimations can vary depending on the selection of the estimating equation used, the choice of the market index and the specific time period that is selected. Furthermore, corporate decisions influence the risk of a firm. As these decisions are taken based on the allowable rate of return of the firm, the regulator may influence the empirical measure of risk used in the cost of capital calculation.

Roll and Ross (1983) compared the historically achieved cost of equity capital for a sample of regulated utility companies with the CAPM estimate of the cost of equity. They found that the CAPM consistently underestimated the cost of equity relative to their historic average.

Empirical testing by Chrétien and Coggins (2011) found that risk premiums calculated using the CAPM were rejected as they were too low compared to historical risk premiums. These findings were ascribed to the well documented propensity of the CAPM to understate the return of low beta, value stocks. They conclude that their findings indicate that models that include factors beyond the CAPM beta have the potential to improve the estimation of the cost of equity capital of energy utilities (Chrétien & Coggins, 2011).

Schaeffler and Weber (2011) performed a study in order to assess whether the choice of regulators to use only the CAPM is appropriate. They estimated the cost of equity capital of 20 network utilities using the CAPM, Fama and French Three Factor Model (FF3F) and Arbitrage Pricing Theory (APT) models. They found that both of the multi-factor models have more explanatory power than the CAPM and that they result in a higher cost of equity estimate than the CAPM.

Furthermore, Schaeffler and Weber (2011) found that the inclusion of the Small Minus Big (SMB) factor is significant and that the FF3F results in an additional cost of equity of 0.4% to 0.6% (Schaeffler & Weber, 2011). Refer to Section 2.8.4 for a fuller discussion of the FF3F and its additional factors. They therefore conclude that it is not appropriate for regulators to use only the CAPM. However, Schaeffler and Weber (2011) continue that the inclusion of additional premiums leads to a reduction of intuitiveness and also requires additional assumptions regarding the risk premiums. This could be contested by regulated firms.

The CAPM is widely used in a regulatory environment (Jenkinson, 2006, pg. 146-163; Sudarsanam et al., 2011). This is due to the fact that it is a simple model to implement; it is grounded in an appealing theory, being the positive linear relationship between risk and return. However, the CAPM that should be used to estimate a regulated firm's cost of capital cannot be conclusively demonstrated by theoretical arguments (Litzenberger, Ramaswamy, & Sossin, 1980). As the CAPM assumes a fully diversified investor, it will not appropriately compensate for the risk faced by an imperfectly diversified investor (Ahern, Hanley, & Michelfelder, 2011). Fama and French (2004) argue that although the CAPM is a theoretical "tour de force", its empirical problems probably invalidate its use in practice.

2.7. Global CAPM

As the CAPM requires that the market portfolio should include all assets, it has been suggested that the CAPM should be calculated based on a global index as opposed to a domestic one. As markets become more open and barriers to international investment are removed, investors are no longer restricted to the domestic investment opportunity set. Investors may then diversify domestic risks with foreign assets (Harris, Marston, Mishra, & Brien, 2003; Qin & Pattanaik, 2000). Harris et al. (2003) found that ex-ante estimates of the cost of equity using a domestic version of the CAPM showed a better fit than a global version, although the difference was small.

2.8. Multi factor models of CAPM

2.8.1. Intertemporal Capital Asset Pricing Model (ICAPM)

The traditional CAPM is a single period model, although in practice it is assumed to hold intertemporally. An investor that requires to hold his portfolio for a fixed period is likely to make a different choice from an investor that has the option to revise his portfolio constantly (Merton, 1973). Based on this, Merton (1973) deduced an intertemporal version of the CAPM (ICAPM). In the ICAPM, it is assumed that there is a limited set of state variables (such as technology, weather, income) that are correlated with the returns on assets (Miles et al., 2003). The ICAPM is therefore a multi-beta version of the CAPM where the returns on assets are determined based on the sensitivity in the assets returns to these state variables (Breedon, 1979). An empirical weakness of this model is that the set of state variables that may be used as proxies for changes in investment opportunities is too broad (Breedon, 1979; Miles et al., 2003).

2.8.2. Consumption CAPM (CCAPM)

Breeden (1979) further developed the ICAPM of Merton (1973). Breeden showed that the multi-beta ICAPM could be reduced into a single beta model where the return on an asset is proportional to its relationship with aggregate real consumption (Breeden, 1979). This representative agent model, dubbed the consumption CAPM by Miles et al. (2003), is an application of the traditional CAPM where the rates of return depend on the correlation of these returns with the marginal utility of consumption (Kocherlakota, 1996; Miles et al., 2003). It is based on the premise that given uncertainty, the return that an investor will require to maintain his utility may be higher. Therefore, if the covariance is high, selling off a security would greatly reduce the variability of an investor's consumption. In equilibrium, an investor should be indifferent from reducing his risk in this fashion due to the stock's high average return (Kocherlakota, 1996). This is in contrast to the traditional CAPM, which assumes that the typical investor's consumption stream is perfectly correlated with the return on the stock market (Kocherlakota, 1996). This allows the factors which affect the marginal utility of consumption, such as risk aversion, to be included in the model. As Damodaran (2014) notes, equity risk premiums are not only a measure of the risk of an investment, but also of the price which investors assign to that risk, i.e. the average investor's risk aversion level. Therefore higher levels of risk aversion would imply higher equity risk premiums in order to compensate investors (Damodaran, 2014).

2.8.3. Skewness and the Three Moment CAPM

Brigham and Crum (1978) note one of the fundamental assumptions of the CAPM is that it assumes a symmetric distribution of returns. As a result, the CAPM only holds when this is the case in order for the unsystematic risk to be diversified away. However, in the case of regulated utilities this does not hold. This is due to the fact that the upside for public utilities is limited by the regulators, while at the same time investors are exposed to downside risks such as rising costs or other risks (Brigham & Crum, 1978). They note that for normal stocks not limited by regulation, these risks are unsystematic risks which can be diversified away, on the assumption of a normal distribution of returns. However, the skewness of the returns of a utility results in exposure to residual unsystematic risk. As a result, the β estimate of the CAPM will not capture all of the risk that the utility is exposed to and as such will result in an underestimate of the cost of capital estimate. They therefore state that the CAPM is not a useful model for describing the risk-return relationship of a utility (Brigham & Crum, 1978).

The Kraus Litzenberger Three Moment model (Kraus & Litzenberger, 1976) was derived to recognise the impact of skewness on the cost of equity capital. In this case, the third factor in the CAPM is a measure of systematic skewness. Kraus and Litzenberger (1976) state that prior negative empirical findings of the CAPM found that the slope of the CAPM is lower and the intercept higher than that predicted by the traditional model (Black et al., 1972; Friend & Blume, 1970) and that this may have resulted from the omission of the CAPM of systematic skewness.

Conine Jr. and Tamarkin (1985b) tested the impact of skewness on cost of capital estimates of utilities. They found that CAPM's adjusted for skewness, such as the Kraus Litzenberger Three Moment model provide higher estimates of the cost of capital on average (Conine Jr. & Tamarkin, 1985b). Conine Jr. and Tamarkin (1985b) note that more research is warranted.

2.8.4. Fama and French Three Factor Model (FF3F)

Fama and French (1993) argue that the market beta is not the only factor that explains the return on assets. Empirical findings suggest that other factors that have no standing in the CAPM theory have explanatory power, such as size (Banz, 1981; Keim, 1983; Reinganum, 1983) and book-to-market value of equity (Banz, 1981). Fama and French (1992) found that two variables, being size and book-to-market value, appear to describe the cross-section of average stock returns. Fama and French (1993) developed a three-factor asset pricing model of the form:

$$R_i(t) = RF(t) + \beta[RM(t) - RF(t)] + s_iSMB + h_iHML(t)$$

Where $R_i(t)$ is the return on asset i , $RM(t)$ is the return on the market, $RF(t)$ is the risk free rate, β is the measure of the systematic risk of the stock against the stock market, s_i is the Small Minus Big (SMB) regression coefficient, h_i is the High Minus Low (HML) regression coefficient, SMB is the difference between the expected return on a portfolio of small stocks and a portfolio of large stocks and $HML(t)$ is the difference between the expected return on high book-to-market stocks and low book-to-market stocks (Fama & French, 1993).

Rossiter, Maughan and Malko (2010) note that the cost of equity capital as determined by the FF3F model between 2005 to 2007 in the US was consistently higher than the CAPM estimate, however it turned negative in 2008 as a result of economic conditions. They therefore note that the FF3F model is more sensitive to general economic conditions and is therefore more volatile. Furthermore, the FF3F model is more complex to implement. They note that regulators should consider a range of models in the cost of equity estimation but they do not conclude if the FF3F model is appropriate to use for regulators (Rossiter, Maughan, & Malko, 2010).

Chrétien and Coggins (2011) tested the validity of the CAPM, FF3F model and an Adjusted CAPM (including adjustments of the Blume (1975)⁵ type and a bias adjustment as per Litzenberger, Ramaswamy and Sosin (1980)). They find that the FF3F model is better suited for estimating the cost of equity capital for energy utilities than the CAPM and conclude that the model estimates a fair and reasonable rate of return for regulators. The FF3F model delivered higher costs of equity than the CAPM. They do note that the reason that regulators have not widely accepted the FF3F model is due to the debate on the size of the additional factors (Chrétien & Coggins, 2011).

Wright et. al. (2006) investigated the use of the FF3F model to estimate the cost of equity for nine UK listed utilities. They found weak statistical evidence for a significant role of the additional two factors and the risk premia associated with the factors. They did note that the “value” effect was the more significant of the two additional premia on the CAPM. They estimated that this effect would increase the cost of equity by 1.25% (Wright, Mason, Satchell, Hori, & Baskaya, 2006).

This is in contrast to the findings of Schaeffler and Weber (2011) that the SMB factor is the most significant. They found that the FF3F model results in a cost of equity that is 0.4% to 0.6% higher than the CAPM. In their study comparing the APT, CAPM and FF3F models, they found that the FF3F model is superior to the other two. They found that APT is superior to the CAPM but was only superior to the FF3F model in one case.

Schaeffler and Weber (2011) developed a two-factor model, which only included the SMB factor of the FF3F model. They concluded that their approach to estimate the SMB factor is straightforward to implement and therefore recommend that this should be included in estimating the cost of equity in future given the significance of the SMB factor.

2.8.5. Arbitrage Pricing Theory (APT)

Ross (1976) developed the APT as an alternative to the mean variance CAPM. The APT states that the returns on an individual stock depend upon a variety of anticipated and unanticipated changes in the market. These changes will affect all stocks in systematic ways, however certain stocks will be more sensitive to these changes (Roll & Ross, 1983). The form of the APT is:

$$\tilde{\chi}_i = E_i + \beta_{i1}\tilde{\delta}_1 + \dots + \beta_{ik}\tilde{\delta}_k + \tilde{\epsilon}_i$$

Where: E_i is a constant for asset i , β_k is the sensitivity of the i asset to the factor k , $\tilde{\delta}_k$ is a market factor return and $\tilde{\epsilon}_i$ is the assets noise term with the mean of zero (Ross, 1976).

⁵ Refer to Section 2.9.2.1.2 for a fuller discussion of the Blume adjustment.

The APT model does not specify which factors should be included in the model. Chen, Roll and Ross (1986) found that several economic variables were significant in explaining expected stock returns. These factors were industrial production, change in the risk premium, twists in the yield curve and measures of unanticipated inflation or changes in expected inflation when these variables were volatile. This is not an exhaustive list (Chen, Roll, & Ross, 1986). Schaeffler and Weber (2011) used these factors when comparing the CAPM to the APT.

Roll and Ross (1983) found that the CAPM estimates of the cost of capital of utilities consistently underestimate realised returns. APT derived estimates of the cost of capital were found to be greater than the CAPM estimates. Schaeffler and Weber (2011) also found that the APT resulted in a higher cost of equity estimate than the CAPM. Roll and Ross (1983) state that this is due to the fact that utilities differ substantially in their factor sensitivities. Utilities have a greater sensitivity to the factor portfolio that mimics unanticipated inflation due to its impact on interest rates. This risk is not properly captured within the CAPM (Roll & Ross, 1983).

Bower, Bower and Logue (1984) tested the performance of the CAPM versus the APT relating to US utility companies. They found that the APT provides a better description of the returns generating process than does CAPM. Schaeffler and Weber (2011) also found that the APT model has better explanatory power than the CAPM. Bower, Bower and Logue (1984) do note that other tests of the APT may make different choices in terms of the form and the estimation methods of the APT, which may result in less favourable results for the APT. They recommend that the regulators give more weight to the APT in decisions (Bower, Bower, & Logue, 1984).

Gözen (2012) and Sudarsanam, Kaltenbronn and Park (2011) note that the APT input factors are not known ex-ante. As a result it is not an easy and verifiable model to be used in a regulatory setting. Gözen (2012) recommends that the APT should not be used in a regulatory environment due to the lack of clear guidance on the inputs (Gözen, 2012).

2.9. The components of the CAPM

Regulators' judgements on the cost of equity methodology are not limited to the selection of the model, as there is little consensus as to the inputs into the CAPM. Practical consideration on their estimation, such as the selection of geometric or arithmetic averaging to calculate the equity risk premium or the use of beta adjustments (see Section 2.9.2.1.), can have a material impact on the calculated cost of equity. As a result, it is necessary to consider the academic literature that relates to the estimation of the determinants of the cost of equity in order to fully evaluate the regulators cost of equity methodologies.

2.9.1. Equity risk premium

The equity risk premium is one of the key components of the CAPM. However, in spite of its importance there is relatively little consensus on the theoretical justification of observed levels and on its determination in practice (Damodaran, 2014; Donaldson, Kamstra, & Kramer, 2010).

2.9.1.1. The Equity Premium Puzzle

The high observed equity risk premium has not been satisfactorily explained using standard economic theory. Researchers have attempted to explain the observed equity risk premiums theoretically using a representative agent model.

Mehra and Prescott (1985) were the first to attempt a theoretical justification of observed equity risk premiums. They used the consumption CAPM as a model to create a theoretical level of the equity risk premium required to compensate investors, given the assumed risk aversion level of the average investor. Based on their work, they found that the theoretically largest possible equity risk premium is 0.35% (Mehra & Prescott, 1985). This is in stark contrast to the large arithmetic average equity risk premium calculated over the period from 1889 to 1979 of 6.18%. Mehra and Prescott (1985) show that the differences in the covariance of returns with consumption growth is only large enough to explain the observed equity premiums if investors are implausibly risk averse (Kocherlakota, 1996; Mehra & Prescott, 2003). This finding is confirmed by Weil (1989). Mehra and Prescott (1985) dubbed this the “equity premium puzzle”.

Mehra and Prescott (1985) note that the equity premium puzzle may not be why the average equity return is so high but rather why the risk free rate is so low. This is taken further by Weil (1989). According to the standard models of individual preferences, individuals want consumption to be smooth over states i.e. they dislike risk (Kocherlakota, 1996; D. Miles et al., 2003; Weil, 1989). Furthermore, investors want consumption to be smooth over time, i.e. they dislike growth in consumption (Kocherlakota, 1996; Mehra & Prescott, 2003). Investors therefore prefer stocks that pay off when consumption is low (stocks that have a lower beta to consumption) as these smooth the consumption profile. As a result, these stocks require a lower return to induce investors to invest (Mehra & Prescott, 2003). Mehra and Prescott (2003) note that consumption growth rates of 1.8% appear to refute this statement as it implies that investors are saving now and increasing consumption in future.

As a result, Weil (1989) concludes that the high rate of consumption is not consistent with the low observed risk free rates, as it implies that investors prefer consumption tomorrow over consumption today (Miles et al., 2003). The standard theory implies that individuals should borrow from their futures to increase consumption in their present, resulting in a smooth consumption profile over time. This should result in high real interest rates, which is not the finding in reality (Siegel & Thaler, 2007). Weil (1989) names this the “risk-free rate puzzle”.

Since the Mehra and Prescott (1985) paper, numerous other researchers have attempted to refine the model used by Mehra and Prescott (1985). Adjusted models have found that the equity risk premium will increase, and the risk free rate decrease, with the inclusion of a borrowing constraint in the standard models (Benninga & Protopapadakis, 1990; Constantinides, Donaldson, & Mehra, 2002). Other assumptions that have been made have included adjustments to the models relating to alternative assumptions on preferences, modified probability distributions, incomplete markets, borrowing constraints as well as market imperfections. As this is not the focus of this study, the reader is directed to the surveys of the theory performed by Kocherlakota (1996), Siegel and Thaler (2007) and Mehra and Prescott (2003).

The equity premium puzzle highlights the lack of consensus regarding the equity risk premium among academics. As regulators prefer to use theoretically justified methods, the lack of consensus among academics places more judgement on regulators. The United Kingdom Competition Commission (UKCC) highlighted the difficulty in assessing the equity risk premium, citing the equity risk premium puzzle and the risk free rate puzzle in their determinations (Competition Commission, 2007).

2.9.1.2. Methods of its determination

Damodaran (2014) describes the approaches to estimate the equity risk premium as follows:

1. The standard approach – involves estimating the equity risk premium using historic data by estimating the difference in annual returns on stocks and bonds.
2. The survey approach - The survey approach to determining the equity risk premium involves surveying investors and managers to assess the risk premium.
3. The implied approach –using current share prices or market rates in order to estimate a forward looking estimate of the equity risk premium.

The literature on the equity risk premium has been expanding. New studies have consisted of a common theme of innovation in order to estimate the unconditional cost of equity capital, through using more novel data or more efficient estimation techniques (Donaldson et al., 2010). In spite of this however, there has been little evidence of consensus having been reached.

2.9.1.2.1. The standard approach

The standard approach involves estimating the historic average annual return on stocks and bonds. The equity risk premium is calculated as the difference between these two returns. Over the short term, returns on stocks and bonds will vary due to random and unanticipated re-pricing of assets, however over a sufficiently large number of observations, investors will realise the return differential resulting from the greater risk of common stocks (Carleton & Lakonishok, 1985). The use of the standard or historical approach is based on the assumption that historical realisations of the equity premium are good predictors of future values and that risk premiums are constant over time (Harris & Marston, 1992). Arnott and Bernstein (2002) caution against extrapolating the extraordinary historical returns into the future. They find that the current risk premium is zero and a sensible expectation for the future premium is 2% to 4% (Arnott & Bernstein, 2002). Dimson, Marsh and Staunton (2000) also conclude that the historically realised equity risk premium is likely to overstate investors current required equity risk premium. Regulators tend to set the equity risk premium in a regulatory determination below the historically realised values (Schaeffler & Weber, 2011).

The standard approach is fraught with complexities. The use of different methods or bases for the calculation can result in significant differences in the outcome. Carleton and Lakonishok (1985) note that the result is affected by the selection of geometric vs arithmetic mean returns, equally weighted portfolios vs value weighted stock portfolios to assess the returns, the time periods selected, bills vs bonds as the basis for the equity risk premium, industry risk-adjusted differentials, effect of data point intervals on industry risk differentials, the significance of some industry “alphas” and the size effects within industries.

Of these factors, Damodaran (2014) identifies the time period, method of averaging returns and the selection of risk free rates and market indices as being the major reasons for divergence in results.

Furthermore, some countries (particularly emerging market economies) have markets with short and volatile histories. These markets tend to be highly concentrated in a few large stocks and trading outside of these large stocks is rather thin. As a result the equity risk premiums calculated on these markets can be unreliable. Damodaran (2014) showed estimates of equity risk premiums of Brazil, China and Mexico where the standard error of the estimates were 10.69%, 6.95% and 8.28% respectively. Damodaran (2014) therefore concludes that historical premiums in these markets should not be used in a CAPM. He therefore recommends estimating the equity risk premium for a mature market (such as the US) and then adjusting this for a country risk premium.

2.9.1.2.1.1 Time periods

The calculation of the equity risk premium can be based on differing time periods. Mehra and Prescott (1985), calculate the premium using information from 1889 to 1979 of 6.18%. In the 1960's and 1970's, it was assumed that based on the efficient market hypothesis, the true equity risk premium was a constant. As a result, as more information became available, estimates would be updated to converge the observed premium to the true premium. However, further studies suggested that this is not the case, that the equity risk premium was in fact a state variable, whose value must be calculated at each point in time based on available data (Campbell, 2008). Carelton and Lakonishok (1985) calculated an arithmetic average equity risk premium of 12.4% between 1941 and 1980 compared to 7.2% between 1966 and 1980.

As a result, it is evident that the risk premium can change over time, as a result of changing dynamics, such as average risk aversion levels. Therefore more recent information will provide a more updated estimate. This should be weighed against the additional error term as a result of fewer data points (Damodaran, 2014). Damodaran (2014) estimates that the standard error of a risk premium estimate will decline from 8.94% when estimated over 5 years to 2.23% when estimated over 80 years.

2.9.1.2.1.2 Method of averaging

The historical mean equity risk premium is calculated using arithmetic or geometric averages of historical equity returns. These two methods can result in vastly different results. The arithmetic return will result in a greater estimation of the return. Assuming that returns are log-normal, the arithmetic return will exceed the geometric return by half of the variance of the two returns. Assuming an annual standard deviation of stock returns of 20%, this will result in a 2% difference between the two estimates (Mehra & Prescott, 2003).

As an example, Carleton and Lakonishok (1985) calculated an arithmetic average equity risk premium of 11.4% between 1926 and 1980 compared to the geometric average of 9.1% (standard deviation of 21.9%). Therefore, the selection of the method of averaging can have a significant impact on the cost of equity used to determine the cost of capital.

If it is assumed that the returns on stocks are uncorrelated over time or that investors rebalance their portfolios at the end of each period, then arithmetic averages should be used (Carleton & Lakonishok, 1985; Mehra & Prescott, 2003). When returns are serially correlated, then the arithmetic mean can lead to misleading estimates, in which case the geometric average should be used (Mehra & Prescott, 2003). Over long horizons, mean-reverting components of price tend to result in negative autocorrelation in stock returns (Fama & French, 1988). This evidence would imply that the use of geometric averages would be more appropriate (Damodaran, 2014).

The arithmetic mean would be more appropriate over a single period (e.g. one year) (Carleton & Lakonishok, 1985). Therefore the term of the regulatory period should be considered in selecting the method of averaging.

Over time the arithmetic average results in an estimate of the true mean which is too high and the geometric mean results in an estimate that is too low (Blume, 1974; Indro & Lee, 1997). Blume (1974) developed a horizon-weighted method which was found to be more efficient than a simple average. Indro and Lee (1997) found that a weighted average of the geometric and arithmetic mean has the least bias in estimating the true mean and is more efficient, with the weight of the geometric mean increasing as the horizon increases.

2.9.1.2.1.3 Stock market and risk free rates selected

The use of a value weighted stock portfolio versus an equally weighted stock portfolio can have a significant effect on the risk premium. Carleton and Lakonishok (1985) found that over the period 1926-1980, the arithmetic means of a value weighted stock portfolio and equally weighted stock portfolio was 11.4% and 17.1% respectively. They attribute this to the fact that the equally weighted portfolio ascribes a greater weight to smaller companies, which are more risky, and have been shown to outperform larger companies over time on a risk-adjusted basis (Banz, 1981; Carleton & Lakonishok, 1985; Keim, 1983; Reinganum, 1983; Roll, 1983). This finding would confirm the FF3F model's inclusion of the SMB term.

Therefore it is more appropriate to use a value weighted index, as this is more representative of the returns on the market as a whole, which will be biased towards larger market capitalisation stocks (Damodaran, 2014). This also agrees with Mossin (1966) who notes that the price of risk reduction, as he dubs the equity risk premium, can be seen as an average of those of individual assets. As a result, he notes that the larger that asset in the market, the more weight its risk premiums should carry (Mossin, 1966).

Furthermore, the presence of hindsight in the selection of the indices can result in incorrect premiums calculated. The impact of survivorship bias can result in the premium being overstated by 2.34% (Dimson, Marsh, & Staunton, 2000). All firms that existed during the estimation period, including those that failed or were acquired, should be included in the calculation (Damodaran, 2014).

2.9.1.2.2. The survey approach

As the equity risk premium is the return that investors would require today to invest in stocks, it is logical to ask investors what premium they would require to invest in risky stocks (Damodaran, 2014). The survey approach to estimating a forward looking equity risk premium is therefore to survey a grouping of market participants that are deemed to be representative of the overall market. In practice, analysts, professors and managers are used as proxies (Damodaran, 2014). The survey approach has been used in a number of academic studies (see (Correia & Cramer, 2008; Fernandez, Aguirreamalloa, & Corres, 2013; Fernandez, Aguirreamalloa, & Linares, 2013; Fernandez & Campo, 2010; Graham & Harvey, 2005). Fernandez, Aguirreamalloa and Linares (2013) used a survey approach to calculate an average risk premium in South Africa of 6.8% (up from 5.8% in 2010 (Fernandez and Campo (2010)) and 5.7% in the USA. Correia and Cramer (2008) found a mean premium of 5.35% and PriceWaterhouseCoopers Corporate Finance (2012) find an average range between 4.7% and 6.6% in South Africa. This compares to the 2.98% equity risk premium estimated by Graham and Harvey (2005) based on a survey of CFO's in the United States.

There are a number of limitations of using the survey approach in practice. Survey premiums are responsive to recent movements in stock prices, with surveyed premiums increasing after bull markets and decreasing after market decline (Damodaran, 2014). The survey premiums can be affected by the sample selected for the survey. Men tend to be more overconfident than woman in trading (Barber & Odean, 2001). Furthermore, woman tend to be more risk averse, which would imply that they would require an increased equity risk premium (Halko, Kaustia, & Alanko, 2011).

Halko, Kaustia and Alanko (2011) found a positive relationship between age and willingness to take risks in Finland. They do note that this may be as a result of the impact of borrowing constraints as was found by Constantinides, Donaldson and Mehra (2002). Investor sentiment has been shown to display a negative relationship with stock returns (Fisher & Statman, 2000). Therefore, investors becoming more optimistic and therefore demanding higher premiums, may in fact be an indication of poor stock returns (Damodaran, 2014).

Fernandez, Aguirreamalloa, and Linares (2013) and Fernandez, and Campo (2010) surveyed managers, analysts, professors. The average equity premiums from their findings are shown in Table 1.

Table 1: Equity risk premium comparison (2010 vs 2012)				
Country	Year	Professors	Managers	Analysts
South Africa	2010	5.50%	5.80%	5.80%
South Africa	2012	7.10%	6.10%	6.80%

It can therefore be seen that the three surveyed groups have different estimates of the required equity risk premiums (Fernandez, Aguirreamalloa, & Linares, 2013; Fernandez & Campo, 2010). These studies also showed that the equity risk premium used in emerging markets is lower than that used in developed markets (Fernandez, Aguirreamalloa, & Corres, 2013).

2.9.1.2.3. The implied approach

The implied approach involves using current stock prices or risk premiums in non-stock markets to estimate a forward looking estimate of the equity risk premium.

As the price which an investor is willing to pay now, per the DCF model, is the present value of the future stream of dividends, we can use this to estimate an investor's required rate of return (Damodaran, 2014). Using the DCF model, based on the known numbers of price, dividends and future growth, the required return on equity can be estimated. If the risk free rate is subtracted from this, the implied equity risk premium is left (Damodaran, 2014). Refer to section 2.4 for a more thorough discussion of the DCF model.

The equity risk premium has also been estimated based on accounting fundamentals (O'Hanlon & Steele, 2000). O'Hanlon and Steele (2000) estimated the cost of equity capital based on the time series relationship between accounting profitability and unrecorded accounting goodwill for a sample of UK firms between 1968 and 1995. O'Hanlon and Steele (2000) then estimated the equity premium by plotting the cost of equity estimates against the CAPM betas for the sample companies. O'Hanlon and Steele (2000) estimate that the UK equity risk premium based on this method is 5% and agree this estimate to the 3.5% to 5% used by the UK's monopolies and Mergers Commission, indicating that it is a comparable method to that used in regulation.

2.9.2. Beta

The beta coefficient has been one of the most debated issues among interested parties with regards to the application of the CAPM and its use in a regulatory environment no less so. As an example, in the US expert witnesses in public utility rate of regulation hearings need to justify a number of their beta assumptions, particularly with regards to the selection of the estimation interval, the estimation period, the selection of the market index, the return definition and whether or not adjustments would be made to the estimate for regression tendencies (Cooley, 1981).

Beta is customarily measured using ordinary least squares (OLS) regression on past data using the market model as per Sharpe (1964). This method can result in significant sampling error in the beta estimate (Lally, 1998). Furthermore, the estimation interval can impact the estimate as betas estimated using daily or weekly data points will be subject to trading patterns. Also, beta estimates of infrequently (frequently) traded stocks have been found to be downward (upward) biased (Dimson, 1979). There are no such biases in the use of monthly intervals to calculate the beta (Carleton & Lakonishok, 1985).

One of the first major critiques of the use of beta in a regulatory context was written by Brigham and Crum (1977) and elicited a vibrant debate among researchers. They argued that historical beta may be a biased estimator of a firm's true beta whenever a company undergoes a change in its systematic risk position without a commensurate change in the return on its assets. This is because should the decrease in risk not be compensated by an immediate increase in earnings, the share price will drop. As a result, the most recent holding period return used to estimate beta will be lowered, resulting in a biased estimate of the true beta.

Brigham and Crum (1977) cite the period from 1964 to 1975, where electricity utilities faced increasing fundamental risk pressure resulting from fuel shortages, environmental problems, and uncertainties about future demand while telephone utilities faced increasing debt ratios and rising competition. In spite of these risk-increasing factors, the beta coefficients remained essentially unchanged over the period. Brigham and Crum (1977) argue that this is an indication of the historical beta not reflecting the true beta and conclude that for public utility rate cases, the use of CAPM should be cautioned as the historical beta does not necessarily reflect the risks inherent in utility stocks.

Gilster and Linke (1978) contend that Brigham and Crum's (1977) findings depended on the assumption of a perfectly negative correlation between two factors. They showed that the size and closure of the rate of the discrepancy between a firm's regression-estimated beta and its true beta, subsequent to a structural shift in the firms systematic risk, are a function of the correlation between changes in the holding period returns due to the changes in the true beta and changes in the holding period return due to all other stocks. If the correlation was positive, the estimated beta would tend to rise above the true beta. Gilster and Linke (1978) note that this is not a unique limitation of the CAPM.

Pettway (1978) performed a study to test the structural stability of betas of public utility entities in the period 1971-1978. The study included a number of shocks, such as Consolidated Edison's decision in 1974 not to declare a dividend. The study found that there were periods where the ex-post estimation of the beta was good enough to provide good estimates of the subsequent values. There were some periods of significant disturbances where the parameters were not good estimates of future values. These periods of instability lasted for longer than one year and were characterised by increased error terms. The periods of instability were found to be transitory with the values of the observed betas returning to their former levels where they were insignificantly different from previous estimates and the error term reduced significantly (Pettway, 1978). Based on this, Pettway (1978) conclude that ensuring that structural parameters are observed carefully, ex-post beta estimates may be used in a regulatory environment.

Dimson and Marsh (1983) note that the non-stationarity of beta results in a trade-off between the statistical efficiency of the estimate and contemporaneity. As a result, the choice of the beta estimation period will depend on the process by, and the speed which, the beta changes over time (Dimson & Marsh, 1983). In the UK a longer estimation period results in an increase in the stability of the beta estimate. Dimson and Marsh (1983) found no evidence that an increase in estimation period results in an increase in bias or inefficiency and conclude that the additional data more than compensates for the use of older data. This finding has been confirmed in other studies (Eubank Jr. & Zumwalt, 1979). The benefits of additional data from extending the estimation period beyond 5 years becomes more and more marginal (Dimson & Marsh, 1983).

2.9.2.1. Beta adjustments

Two major problems have been identified with OLS estimated betas; 1) betas are time varying (Blume, 1971; Dimson & Marsh, 1983; Lally, 1998) and 2) betas are subject to significant estimation error (Lally, 1998; Vasicek, 1973). A number of methods have been developed to adjust the betas for these effects, however the most widely accepted methods are the Blume and Vasicek methods (Lally, 1998). The decision as to whether to adjust the beta for its regression tendencies is commonly debated in US rate regulation hearings (Cooley, 1981).

2.9.2.1.1. Vasicek adjustment

Vasicek (1973) used Bayesian decision theory to construct a model of beta estimation that minimises the expected squared estimation error. The model uses the prior distribution of securities in order to generate Bayesian estimates of the beta (Vasicek, 1973). Lally (1998) notes that the Vasicek model does not forecast the beta, but rather only deals with the sampling error of a beta estimation. Vasicek's model is as follows:

$$\beta_j'' = \frac{(\beta_j' / S_{j' b^2}) + (\hat{\beta}_j / S_{j b^2})}{(1 / S_{j' b^2}) + (1 / S_{j b^2})}$$

Where, β_j'' is the Vasicek estimator of the true beta of the security j , β_j' is the mean of the prior distribution of the cross sectional betas of security j , $S_{j' b^2}$ is the variance of the estimate of β_j' , $\hat{\beta}_j$ is the OLS estimated beta coefficient for security j , $S_{j b^2}$ is the variance of the estimate of $\hat{\beta}_j$ (Vasicek, 1973).

2.9.2.1.2. Blume adjustment

Blume (1971) found that the estimated values of the risk coefficients are biased estimators of the future values. Furthermore, the values of the risk coefficients as measured by beta tend towards the mean and this tendency was found to be stronger for lower risk portfolios than for higher risk portfolios (Blume, 1971, 1975). In order to adjust for this tendency, Blume (1971) regressed the estimated values of beta in one period on the values estimated in a previous period and used the relationship found to modify the assessments of the future. Blume (1971) found that the assessments of beta adjusted for the historical rate of regression were more accurate than unadjusted estimates. Blume (1971) concludes that to improve the accuracy of the estimates of the beta, it should be adjusted by historical rate of regression. Blume (1971) does note that the historical rate of regression is not consistent over time. The Blume formula takes the form:

$$\beta_j^B = a + b\hat{\beta}_j$$

Where β_j^B is the Blume adjusted measure of systematic risk for asset j , a and b are the coefficients from cross-sectionally regressing betas estimated in one period against those estimated in a prior period. The commonly used Blume parameters for a and b are 0.33 and 0.67 respectively (Aharonian et al., 2010; Lally, 1998).

Lally (1998) notes the following sources of difference between the Vasicek and Blume methods; both Blume and Vasicek contain noise terms specific to their particular estimation processes, the Blume methodology acts as if the error term is the same for all stocks, the Blume methodology extrapolates the true beta to tend towards a mean of one whereas the Vasicek methodology does not forecast the beta and Blume is conventionally applied to all stocks in aggregate whereas Vasicek is applied to industry subsets.

Dimson and Marsh (1983) found that the use of Vasicek and Blume adjusted betas results in a far better forecast of beta than a naïve model. They found that both models led to a reduction in inefficiency, with the Bayesian model being slightly superior. This was also found in the US by Klemkosky and Martin (1975) and Eubank and Zumwalt (1979), although Eubank and Zumwalt (1979) found that the Blume adjustment procedures were superior.

Elton, Gruber and Ulrich (1978) found that the Blume model outperforms the Vasicek model. Lally (1998) argues that the Vasicek model is a better estimation method. His reasoning is due to the fact that the Blume model estimates that the error term is the same for all securities which Vasicek does not. Furthermore, the Blume model is constrained to both forecasting the beta as well as assuming a certain forecasting technique. At least one of these may be undesirable in certain situations, whereas Vasicek is not similarly constrained. Lally (1998) notes that previous empirical studies prefer the Blume model based on the assumption of beta being mean reverting towards one. He argues that this historical tendency, based on the sampling theory, is not an immutable law.

Gombola and Kahl (1990) performed a study relating to the process of forecasting utility betas using time series process. They found that the most common time series process of the beta of utilities is the auto-regressive process. They conclude, in line with the Blume and Vasicek adjustments, that when beta is time varying, an unadjusted short-term OLS estimate of the beta may not be the best estimation. They recommend that the forecaster make use of the betas auto regressive tendencies and adjust the beta towards an underlying mean beta (Gombola & Kahl, 1990). Gombola and Kahl (1990) state that their findings strongly support the use of a Bayesian adjustment process, such as that proposed by Vasicek (1977). Gombola and Kahl (1990) state that the Blume (1971) adjustment, which assumes a mean of one, overstates the mean beta of a utility. The beta should be adjusted towards a mean of less than one. They conclude that using an adjusted beta permits the use of CAPM, even if the beta is time varying.

Chrétien and Coggins (2011) performed an empirical test of the CAPM, FF3F model and an Adjusted CAPM. The Adjusted CAPM which they used included a beta adjusted using the Blume adjustment. They also adjusted the CAPM using Bayesian techniques as proposed by Litzenberger, Ramaswamy and Sosin (1980). They find that the Adjusted CAPM is a useful model for regulators to use as it appears better specified than the CAPM. Also, they find that the cost of equity estimates from this Adjusted Model are greater than that derived from the traditional CAPM (Chrétien & Coggins, 2011). This finding has been repeated in similar studies (Pastor & Stambaugh, 1999). Pastor and Stambaugh (1999) also found higher cost of equity estimates using an adjusted CAPM for energy utilities than using the CAPM.

2.9.2.2. Levering and unlevering the beta

Hamada (1972) notes that both in the CAPM and in Modigliani and Miller's (1958) theory, the presence of borrowing increases the risk to the investor. Therefore the beta should be greater for the firm with a higher debt equity ratio (Hamada, 1972). This would result in k_e increasing for higher levels of leverage as a result of the increased financial risk borne by the shareholder (Harris & Pringle, 1985).

The WACC is only appropriate for evaluating projects that are of average risk to the firm as it assumes that the investment will be financed with incremental funds in the same proportions as used in calculating the WACC (Harris & Pringle, 1985). A number of models have been created which adjust for the impact of the increased financial risk on a firm.

2.9.2.2.1. The Hamada formula

Hamada (1972) wrote a seminal paper on the need to take into account the impact of increased debt on the systematic risk of a firm. In this paper the Hamada formula was developed. The model takes the form:

$$\beta_U = \frac{\beta_L}{(1+(1-T)\frac{D}{E})}$$

Where β_U is the beta of the unlevered firm, β_L is the beta of the levered firm, T is the corporate tax rate, D is the market value of debt and E is the market value of equity (Fernández, 2006).

Conine Jr. (1980) notes that the Hamada formula assumes that the beta of debt is zero, i.e. that the debt is risk free. This may result in a bias in the estimation of the cost of capital. Results may be further biased if the capital structure includes risky preference shares as these are also not considered in the formula. Conine Jr. (1980) presented a model for levering beta that includes the risky debt and risk preference share capital (Conine Jr., 1980). Conine Jr. and Tamarkin (1985) note that the use of market values in the formula may overstate the results due to the volatility of market data.

2.9.2.2.2. The Miles-Ezzell formula

Miles and Ezzell (1980) developed a methodology for levering and unlevering the beta on the assumption that the firm maintains a constant market-value leverage ratio (L). They assume that if, at the end of each period, the debt to total value does not equal L, the firm will go in the market and do a financial transaction to restore the ratio to L (J. A. Miles & Ezzell, 1980). As a result, the Miles-Ezzell formula is as follows:

$$\beta_e = \beta_u + \frac{D}{E}(\beta_u - \beta_d)\left[1 - \frac{(T \times k_d)}{(1+k_d)}\right]$$

Where, k_d is the cost of debt and β_d is the beta of debt.

2.9.2.2.3. The Fernandez model

Fernandez (2006) developed a formula for the levering and unlevering of beta, assuming that the firm maintains a constant book-value leverage ratio and there are no costs of leverage. He states that this is more realistic than the assumption of the Miles and Ezzell (1980) that a firm maintains a constant market-value leverage ratio. The Fernandez formula is as follows:

$$\beta_L = \beta_U + (\beta_U - \beta_D)(1 - T)\left(\frac{D_{BV}}{E_{BV}}\right)$$

Where D_{BV} is the book value of debt and E_{BV} is the book value of equity. In a regulatory environment where the book-value capital structure is kept constant, the Fernandez model is more appropriate (Aharonian et al., 2010).

2.9.2.2.4. The Harris-Pringle formula

Harris and Pringle (1985) proposed a model to adjust for the effect of leverage on risk adjusted discount rates assuming that the firm will constantly balance the weightings of its debt to equity and keep the ratio of debt to equity equal. The Harris and Pringle model is:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D)$$

Taggart (1991) notes that the Harris and Pringle (1985) model should be used where the firm constantly readjusts its debt to equity ratio to the target ratio and the Miles-Ezzell model is preferred where the firm adjusts its debt to equity ratio once per year (Taggart Jr., 1991).

Gözen (2011) notes that in practice the β_d is often assumed to be zero or very small. However, this therefore assumes that the company can borrow at the risk free rate which is unrealistic. Elton et al. (2001) note that the spread of corporate bonds are affected by the loss from expected default, taxes which must be paid on corporate bonds and not on government bonds, and a premium required for bearing systematic risk. The beta of BBB industrials bonds has been found to average 0.26 (Elton, Gruber, Agrawal, & Mann, 2001).

2.9.2.3. Impact of regulation on beta

There are a number of arguments as to the impact of regulation on the risk of an entity. Some academics argue that regulation results in a reduction of systematic risk, whereas others argue the opposite.

A number of factors have been cited as leading to a reduction in systematic risk due to the firm being regulated. Firstly, risk can decline as a result of the wealth distribution process. The benefits of government regulation accrue to the firm and consumers represented in a market. Demand or cost disturbances generate conventional price and profit fluctuations; however these are weakened by the regulatory process. As a result the producer risk is lowered (Norton, 1985). Secondly, the reduced risk can be seen as a result of direct constituent preference. The risk relating to an entity may be reduced as a result of a responsive political system (Norton, 1985). For example, Clarke (1979) found that the use of the fuel adjustment clauses of electric utilities in the 1970's in America resulted in a ten percent decrease in systematic risk on average. The risk in this case was passed from the producer to the consumer (Clarke, 1979).

Other researchers contend that regulation tends to increase risk, particularly during periods of increases in input prices. As an example, rising inflation can lead to an increase in risk for utilities and a subsequent increase in the cost of capital (Keran, 1976). Holmberg (1977) found a substantial increase in investor risk and required rate of return on regulated utilities from 1950 to 1974. This was ascribed to a number of factors including rising inflation, regulatory lag, inadequate allowed rate increases and the need to add more expensive plant capacity among others (Holmberg, 1977).

Norton (1985) studied the impact of an entity being regulated on its systematic risk and found that the presence and strength of incentive regulation strongly affects systematic risk. The beta is endogenous to regulation (Norton, 1985). Furthermore, Norton found that systematic risk is also lower in regulated versus unregulated regimes. Beta is also lower the more intensive the regulatory regime. Alexander, Estache and Olivieri (2001) tested the impact of the regulatory regime on the systematic risk of a sector, focussing on transport. The study classified regulatory regimes as high powered (for example CPI-X price cap in the UK) and low powered (for example, rate of return regulation in the US) and found a positive relationship between the regulatory regime and systematic risk. Furthermore, Alexander, Estache and Olivieri (2001) found that market structure and inter-model competition also affects beta estimates and may lead to a breakdown in this relationship (Alexander, Estache, & Oliveri, 2001). This is therefore an important factor for emerging market regulators, where regulated companies may not be listed, to consider in selecting comparable companies. The regulatory environment of the companies selected as well as the market structure should be considered.

2.9.2.3.1. Divisional Cost of Capital

A problem arises in regulation where there is limited stock market data from which to estimate the beta, or the firm is not listed (Sudarsanam et al., 2011). This is a common issue in regulation as the regulated activity is normally run within a non-listed business or the holding company is not listed. As a result, a market related beta is not measurable (Fuller & Kerr, 1981; Gup & Norwood III, 1982; Sudarsanam et al., 2011). Where the regulated utility is not listed on the applicable stock exchange, comparator data must be used to estimate the beta (Gözen, 2011; Sudarsanam et al., 2011). The method of calculating a beta based on comparator companies is named the divisional cost of capital method.

This may also be important in estimating the cost of equity capital of a division of an integrated utility. As an example, Eskom operations include generation, distribution and transmission. These may be subject to different risks, and therefore have different beta estimate. Integrated utility firms have been found to have a higher beta estimate than a pure network utility (Schaeffler & Weber, 2011). They found that regulators include integrated utilities in their proxy samples to calculate the beta of network operators, which would result in the beta of the network operator being overstated and increasing the cost of equity.

The divisional cost of capital was espoused by Fuller and Kerr (1981), who noted that the use of a single cost of capital for an entire firm is inappropriate. This is due to the fact that divisions within the firm will be subject to different levels of systematic risk. In a regulatory environment, a divisional cost of capital should be used to calculate the required rate of return for a regulated subsidiary of the firm (Ezzell, Hsu, & Miles, 1991). As the measure of systematic risk of a company is the beta, a number of approaches have been identified in the literature. Fuller and Kerr (1981) describe two methods to calculate the cost of capital of a division; the analytic approach and the “pure-play” technique.

The analytic approach links historical earnings data to market estimates of systematic risk and debt capacity. Weston (1973) proposed that the beta of a division should be estimated subjectively based on a number of factors based on pro-forma financial results including profitability and correlation of output with economic growth. Other studies proposed similar measures of systematic risk (Gordon & Halpern, 1974; Gup & Norwood III, 1982; Weston & Lee, 1977). Harris, Brian and Wakeman (1989) note that it is preferential to use methods consistent with financial theory as there are a number of problems inherent in estimating and using ad hoc relationships.

The pure-play technique involves finding publically traded securities which are engaged solely in the same line of business as the division. Once the pure-play firm has been

determined, its cost of capital is used as a proxy for that of the division. This assumes that the systematic risk and capital structure is the same for the pure-play as for the division (Fuller & Kerr, 1981).

Fuller and Kerr (1981) found that the pure-play technique is an appropriate method of calculating the beta of a division and the beta of a multi-division firm can be determined as a weighted average of the betas of its divisions. Fuller and Kerr's (1981) model involved weighting the betas determined for proxy companies by their sales weightings. They found that unadjusted pure-play betas provided better approximations of the multi-division firm's beta than leverage-adjusted betas and recommended that capital structure can be ignored in the determination. Therefore this essentially assumes that the leverage of the pure-play companies can be used as the imputed leverage ratio of the division. They did note that since previous studies had identified capital structure as an important variable, that statement should be viewed with caution and was an area for further research (Fuller & Kerr, 1981).

Conine Jr. and Tamarkin (1985a) reconsidered the effect of leverage on Fuller and Kerr's (1981) findings. They found that Fuller and Kerr's results were biased due to the use of the Hamada model to adjust the beta for the impact of leverage of the study. This is due to the fact that the Hamada model does not incorporate risky debt into the formula (Conine Jr. & Tamarkin, 1985a). Furthermore, adjustments were not made where risky preference share capital in the capital structure. Conine Jr. and Tamarkin (1985a) reperformed Fuller and Kerr's (1981) empirical study using an adjusted leverage model including the impact of risky debt and risky preference shares. They found that their adjusted model resulted in substantially more accurate forecasts than the Hamada adjusted betas. However, they did find that the betas were still higher than those where no leverage adjustment was made. They identified a number of reasons for this, including the use of implied bond and preferred betas, noise in the data characteristics, leverage based on the standard pricing model rather than a non-standard form, or leverage adjustments based on market values (Conine Jr. & Tamarkin, 1985a).

Ezzell, Hsu and Miles (1991) note that the "pure-play" approach to calculate the cost of equity for divisions as used in Fuller and Kerr (1981), Van Horne (1980) and Gup and Norwood III (1982) does not take into account the "double leverage" problem. This relates to the required rate of return for a levered subsidiary that should account for interest tax savings on the subsidiary's debt as well as on the holding company's debt. The "pure-play" technique ignores the value of the subsidiary's tax savings and is therefore not appropriate to be used in rate regulation. Ezzell, Hsu and Miles (1991) derived a specification of the model for rate of return regulation whereby regulators would allocate the present value of the

parent companies tax savings across the subsidiaries. This specification assumes that the net tax savings on interest is equal to the corporate tax rate and that the parent and the subsidiary manage their debt levels to maintain predetermined market value debt levels (Ezzell et al., 1991).

Harris, O'Brien and Wakeman (1989) noted that the use of the "pure-play" technique will result in data limitation issues. This is due to the fact that most companies operate across a wide range of industries, and so therefore it may be difficult to identify a number of pure-play comparators. Therefore the pure-play approach ignores a large amount of useful information. They therefore recommend that multi-division firms are used (Harris, O'Brien, & Wakeman, 1989). Fuller and Kerr (1981) showed that the beta of a firm is the weighted average of the beta of the divisions:

$$\beta_j \cong \sum_i \left(\frac{S_{ij}}{S_j} \right) \beta_{ij}$$

Where β_j is the beta of the firm j , S_{ij} and S_j represent the market value of the firm j and its i th division and β_{ij} represents the measure of systematic risk of division i . Harris, O'Brien and Wakeman (1989) note that while the market values of the firm are observable, the market value of its divisions are not observable. Fuller and Kerr (1981) used the proportion of the division's sales to the total sales of the firm. Harris, O'Brien and Wakeman (1989) use the book values of assets as the weights. They prefer the use of the book value of assets as they are a measure of the firm's stock rather than a flow of revenues generated by such assets. They state that the theoretically correct market value weights are also a stock rather than a flow measure. (Harris et al., 1989)

2.9.3. Risk free rate

The estimation of the risk free rate is commonly the most straightforward exercise for the regulator. This is due to the fact that forward estimates can be readily accessed from the bond markets (Jenkinson, 2006, pg. 146-163). In spite of its relative simplicity, regulators need to select whether to use spot estimates or whether to apply a method of averaging rates and the maturity of the debt to assume.

The risk free rate can be estimated using either short-term government securities or long-term government securities. Given an upward sloping yield curve, using short-term (long-term) securities will result in a larger (smaller) equity risk premium (Damodaran, 2014). Although a short-term security is likely to have less risk, as interest rates may change over time, this is only appropriate for a single period investment. Over the longer term, the short-term security will be subject to reinvestment risk, whereas the long-term security will not (Damodaran, 2014). However, long-term bonds will be exposed to inflation risk and to changes in interest rates (Dimson et al., 2000). In a regulatory environment, the selection of the term of the debt is bounded by the regulatory period, i.e. a 5 year term instrument is selected to correspond with a 5 year regulatory period (Jenkinson, 2006, pg. 146-163).

Damodaran (2010) notes that the conventional wisdom would imply that the use of an arithmetic average is the most appropriate rate to use as the CAPM is a single period model and also if one assumes that returns on stocks and bonds are serially uncorrelated. However, Damodaran (2010) continues that as the time horizon lengthens and returns become more serially correlated, it is far more appropriate to use geometric averages. As an example, over a ten year time horizon, the ten year period is in essence the “single period” for the purpose of the CAPM. As a result, the appropriate returns are based on a geometric average. He therefore notes that an arithmetic mean is more appropriate if the short-term treasury bill yield is defined as the risk free rate but that the geometric mean is more appropriate if a longer term treasury bond yield is used for the risk free rate.

This risk free rate used needs to be consistent with the risk free rate used in the estimation of the equity risk premium (Damodaran, 2014).

2.10. Summary of literature review

In summary, it is evident from the preceding consideration of the literature regarding the cost of equity capital, that there is limited agreement on its determination. Considering the requirements of a cost of equity capital model in a regulatory setting as discussed by Aharonian et al. (2010), no model appears to perfectly meet those criteria. Survey based studies have found that the CAPM is the most widely used model in a regulatory environment (Schaeffler & Weber, 2011; Sudarsanam et al., 2011). However, empirical studies have shown that the CAPM tends to understate the returns of utility companies in comparison to realised returns.

Furthermore, empirical studies have found that the FF3F model has better explanatory power than both the CAPM and APT model, and provides a higher estimate of the cost of equity capital. Its lack of use by regulators has been ascribed to the difficulty in determining its factors which may result in it being contested by regulated firms.

Given that no model has a clear advantage to be used in a regulatory environment, regulators' decisions will require judgement on the part of the regulator. This is likely to create differences of opinions, between regulators in different industries and countries as well as with the regulated firms. Chapter 3 will outline the methodology with which the regulatory survey was completed and Chapter 4 will perform the survey of the cost of equity capital methodologies of a sample of regulators.

3. Methodology

The aim of this study is to undertake qualitative research to evaluate regulatory best practice regarding the cost of equity methodology. The study aims to answer the two research questions as introduced in Section 1.4.

Research question 1: How is the cost of equity estimated in a regulatory environment?

Objective 1: To evaluate whether there is consensus among regulators as to the methodology to estimate the cost of equity (including the model and its determinants)

Objective 2: To consider whether the methodologies used by regulators are consistent with theory and empirical findings.

Research question 2: Is NERSA's (South Africa) cost of equity methodology consistent with international practice?

Objective 3: To assess whether NERSA's (South Africa) methodology is consistent with applicable theory, empirical evidence and international best practice and therefore is appropriately compensating Eskom in its regulatory determinations.

In order to evaluate these research questions, the study will evaluate the methodologies used to estimate the cost of equity capital of international regulators.

3.1. Data selection

The cost of equity capital regulatory methodology of regulators will be analysed. Given the aim of this study to evaluate the cost of equity methodology applied by NERSA (South Africa) to ESKOM, the study will focus on regulators which operate within the electricity sector. However, given limitations of this research method, it was impractical to evaluate all regulators. Therefore, regulators were included from economies that have a relatively long history of utility regulation and a well-established regulatory framework. Furthermore, the accessibility of the information and the extent of the disclosure of their regulatory methodology was considered in selecting the sample. The regulators identified on this basis were based in developed economies.

These considerations resulted in Regulators mostly being selected from developed economies. As this study aims to evaluate the methodology used in South Africa by NERSA (South Africa), regulators from developing economies were also selected. These regulators are likely to face issues relating to the cost of equity methodology that are not considered by developed economy regulators. These will therefore provide further evidence regarding the cost of equity methodology to be applied in South Africa.

On this basis, 14 regulators have been selected. These regulators operate across a range of economies and continents, refer to Table 2 for a summary of the regulators selected. Refer to *Appendix B: Description of regulators* for a description of the regulatory agencies.

No.	Regulator	Abbreviation	Country	Level
1	Public Utilities Commission of Ohio	PUCO	USA	State
2	Australian Energy Regulator	AER	Australia	State
3	Agência Nacional de Energia Elétrica	ANEEL	Brazil	National
4	Central Electricity Regulatory Commission	CERC	India	National
5	Commerce Commission	NZCC	New Zealand	National
6	Energy Regulatory Office	ERO	Czech Republic	National
7	Lesotho Energy and Water Authority	LEWA	Lesotho	National
8	Utility Regulator of Electricity, Gas and Water	UREGNI	Northern Ireland	National
9	Competition Commission	UKCC	United Kingdom	National
10	The Office of Gas and Electricity Markets	OFGEM	United Kingdom	National
11	National Energy Regulator of South Africa	NERSA	South Africa	National
12	Ontario Energy Board	OEB	Canada	State
13	Nigerian Electricity and Regulatory Commission	NERC	Nigeria	National
14	Electricity Control Board	ECB	Namibia	National

The latest available cost of equity methodologies published by the regulators were obtained from the regulators websites. Interviews were held with Mr Nkadameng, a senior financial analyst at NERSA (South Africa). Mr Nkadameng was responsible for developing the economic regulation methodologies for the determination of the revenue requirements of regulated entities (Nkadameng D. Interview, 29 October 2014). The regulators' methodologies will be evaluated, with specific focus placed on the following:

1. Model used to estimate the cost of equity capital
2. Method used to estimate the risk free rate
3. Method used to estimate the equity risk premium
4. Method used to estimate the equity beta

These issues have been identified as key judgements on the part of regulators by studies performed by Sudarsanam, Kaltenbronn and Park (2011) and Aharonian, Villadsen and Vilbert (2010).

The above requirements will be evaluated and compared between regulators, including the reasoning behind selecting the method used.

3.2. Criteria for assessing information

As was highlighted by Aharonian, Villadsen and Vilbert (2010), the regulatory environment imposes specific requirements on a cost of equity model and presented a set of requirements which a model should meet in order to be used in a regulatory environment. These requirements were echoed by the AER (Australia) and the OEB (Canada), both of which use a similar set of requirements. The major aim is to improve the transparency of the output, be reflective of the current financial environment, be in line with well accepted financial theory while also being simple to implement. Refer to Appendix 7.1 for the AER (Australia) criteria.

This may result in situations where the regulator selects a model based on more than just the theoretical or empirical justification of the model. Regulators may be influenced by models used in the past, as the UKCC (UK) notes that consistency and predictability of the regulatory approach is in the public interest (Competition Commission, 2014b).

It is also important to consider that differences in the methodologies may be reflective of a different regulatory environment in that company. Regulators may choose to use a post or pre-tax cost of capital estimates, depending on whether the cash flows are inclusive/exclusive of tax. Real cost of capital estimates may be used, such as is used by NERSA (South Africa) and LEWA (Lesotho), in order to avoid remunerating for the inflationary impact of using an asset value based on the current replacement cost. For example, ANEEL (Brazil) and NERSA (South Africa) use a real post-tax WACC (Carvalho & Gabardo, 2013; National Energy Regulator of South Africa, 2013). These considerations are beyond the scope of this study.

The differing levels of disclosure relating to the decision making process of the regulators in assessing the cost of equity capital should also be discussed. This study is based on publicly available published cost of equity methodologies of the regulators. Regulators such as the NZCC (New Zealand), the AER (Australia) and OFGEM (UK) aim to increase the transparency of their determination, which results in initial strategy documents, consultation documents, and then the final decision being published after significant stakeholder involvement. These documents include each point raised by stakeholders, as well as the regulators response, increasing the transparency of the decision. NERSA on the other hand has a policy of not disclosing the information behind the calculation of the cost of equity capital (Nkadimeng, Interview). Furthermore, the extent of the disclosure by regulators is affected by the resources available to the regulator. The regulators from developed economies included greater detail in their determination, allowing for more insight into their methodology.

This may have the impact of resulting in a “disclosure bias”, whereby the judgements of the regulators with greater transparency of the methodology are more evident in the survey. The author was aware of this bias and has attempted to include the perspectives of all regulators included in the survey, where the information was available.

4. Regulatory Survey

This chapter will analyse the cost of equity capital methodologies used by the regulators in the countries shown in Table 2. The chapter will be structured as follows: 1. Cost of Equity model used, 2. Method for calculating risk free rate, 3. Method for estimating ERP 4. Method for calculating equity beta.

4.1. Cost of Equity model used

A summary of the cost of equity model selections is shown in Table 3⁶.

Regulator	Country	Primary model	Secondary Model	Consider other models?	CoE selected
AER	Australia	CAPM		Yes	ND
LEWA	Lesotho	CAPM			ND
NZCC	New Zealand	Brennan-Lally CAPM		Yes	7.11%
ANEEL	Brazil	CAPM		Yes	8.82% to 9.84%
PUCO	USA	DCF	CAPM	Yes	ND
UKCC	UK	CAPM		Yes	3.4% to 5%
UREGNI	Northern Ireland	CAPM			5.70%
CERC	India	None identified			16%
ERO	Czech Republic	CAPM			TSO: 7.923% DSO: 7.65%
OEB	Canada	Risk premium based models			9.36%
NERC	Nigeria	CAPM			29%
NERSA	South Africa	CAPM			8.96%
ECB	Namibia	CAPM			ND
OFGEM	UK	CAPM		Yes	6% [6% to 7.2%]

ND = Not disclosed

The CAPM is the most widely used model based on the regulators included in the survey, with 12 of the 14 regulators using the traditional CAPM or a derivative thereof in their determinations.

⁶ Notes on Table 3: UREGNI's (Northern Ireland) decision was based on "An Estimate of NIE T&D's Costs of Capital" by First Economics (2011). This has therefore been considered for the reasoning behind the assumptions. CERC's (India) cost of equity was 15.5%, however an additional 0.5% was allowed if firms met certain timelines

The AER (Australia), PUCO (USA), NERC (Nigeria), the ECB (Namibia), ANEEL (Brazil), LEWA (Lesotho), NERSA (South Africa), OFGEM (UK), the UKCC (UK), the NZCC (New Zealand), the ERO (Czech Republic) and UREGNI (Northern Ireland) used the CAPM I in their determination of the cost of equity capital (Australian Energy Regulator, 2013a; Carvalho & Gabardo, 2013; Competition Commission, 2014b; Electricity Control Board, 2001; Energy Regulatory Office, 2009; Lesotho Electricity Authority, 2012; National Energy Regulator of South Africa, 2013; Nigerian Electricity and Regulatory Commission, 2012; Nixon, 2014; Regulation Branch Commerce Commission, 2010b; The Staff of the Public Utilities Commission of Ohio, 2013; UREGNI, 2012b).

CERC (India) selected their rate after considering the prime lending rate of Indian banks, the rate on government securities as well as the requirements of the utilities in order to ensure investment in the industry. A rate of 16% was selected (Central Electricity Regulatory Commission, 2014).

In the determination of the cost of equity capital, a number of the regulators explicitly considered the use of alternative models. These models were evaluated in terms of the requirements of a model to be used in a regulatory environment.

4.1.1. DCF

ANEEL (Brazil) noted the existence of the DCF model but did not consider it further (Carvalho & Gabardo, 2013). CERC (India) did note the existence of the dividend growth model, but commented that it would not be appropriate to apply in India due to a lack of a sufficient volume of data (Central Electricity Regulatory Commission, 2014).

The AER (Australia) considered the use of the DCF and noted that it meets some of their criteria as it is simple to implement and the theoretical underpinnings are well accepted and sound. However, the AER (Australia) and the NZCC (New Zealand) highlighted limitations with the model. The AER (Australia) noted that transparent and robust DCF estimates require large amounts of available and reliable data, a situation which is often not possible (Australian Energy Regulator, 2013b). The NZCC (New Zealand) included further limitations; the model is only appropriate for listed entities, the constant growth assumption is only appropriate for stable and mature firms, the model relies on the assumption that markets are efficient and that dividend growth forecasts generally exceed GDP growth. The NZCC (New Zealand) chose not to use the DCF model due to these limitations (Regulation Branch Commerce Commission, 2010b).

Furthermore, the AER (Australia) and the UKCC (UK) both note that the DCF model is very sensitive to changes in the long term growth assumptions. As a result, the AER (Australia) and the UKCC (UK) do not use the DCF to estimate the cost of equity but do use it as a cross-check for the ERP (Australian Energy Regulator, 2013b; Competition Commission, 2014b).

The AER (Australia) uses both a two-stage and a three-stage DCF model to estimate the ERP. Two adjustments are made to the DCF models used; a “partial year adjustment” to adjust for the case when the dividend date differs from the financial year end date and a “midyear convention” to take into account the fact that dividends are generally paid twice a year, as was recommended by Linke and Zumwalt (1984). They note that not including these adjustments can have a material impact (Australian Energy Regulator, 2013b). The AER (Australia) uses the following DCF model:

$$P_c = \frac{m \times E(D_c)}{(1+k)^{m/2}} + \sum_{t=1}^N \frac{E(D_t)}{[(1+k)^{m+t+0.5}]} + \frac{\frac{E(D_N)(1+g)}{(k-g)}}{(1+k)^{m+N-0.5}}$$

Where P_c is the current price of equity, $E(D_c)$ is the current expectation of dividends per share for the current financial year, $E(D_t)$ is the current expectation of dividends per share for the financial year t years after the current financial year, m is the fraction of the current financial year remaining, N is the time period after which dividend growth reverts to its long-term rate, g is the long term growth rate in nominal dividends per share and k is the discount rate.

The PUCO (USA) applied both the DCF model and the CAPM, however the models were applied in a ratio of 3 to 1 in favour of the DCF model. PUCO (USA) did not sufficiently explain this, stating that it was due to the historically lower treasury yields (The Staff of the Public Utilities Commission of Ohio, 2013).

PUCO (USA) used a three-stage DCF model in order to calculate the implied cost of equity. PUCO (USA) used the average daily closing price for each comparable company over a one year period. It was assumed that dividends would grow at the same rate as earnings (The Staff of the Public Utilities Commission of Ohio, 2013). The UKCC (UK) considers this to be an arbitrary assumption as empirical evidence supports lower dividend growth rates than economy growth rates.

The UKCC (UK) therefore prefers the historic growth rate of dividends (Competition Commission, 2014b). PUCO (USA) obtained average analyst earnings per share estimates from a number of service providers. The prior quarterly dividends of the comparable utilities were added together; i.e. no mid-year adjustment was made. These dividends were assumed to grow at the analysts' growth estimates for five years. This was due to the fact that these are indicative of investors' expectations (The Staff of the Public Utilities Commission of Ohio, 2013).

After 25 years, PUCO (USA) assumed dividends to grow at the long term growth rate of gross national product (GNP). This was estimated as the average annual change in the US GNP between 1929 and 2011. Between the 6th and 24th year, dividends were assumed to vary linearly between the two growth rates. These assumptions were used to calculate the IRR of the future dividend stream and the current share price (The Staff of the Public Utilities Commission of Ohio, 2013).

4.1.2. CAPM

The CAPM was the most widely used model based on the regulators surveyed. 12 of the 14 regulators surveyed selected the CAPM as either their primary model or secondary model. The UKCC (UK), AER (Australia) and the NZCC (New Zealand) considered that the model has an established theoretical and empirical base. Furthermore, the inputs can be estimated using relatively simple, robust, replicable and transparent approaches. The CAPM therefore complies with most of the AER's (Australia) requirements for a model as per Appendix A. (Australian Energy Regulator, 2013b; Begg, Duignan, Gale, & Berry, 2013; Competition Commission, 2014b).

The NZCC (New Zealand) also noted that the model is widely used in regulatory decisions and in practice and there is no consensus as to what model is better than the CAPM (Begg et al., 2013).

In coming to this decision, the AER (Australia), the UKCC (UK) and the NZCC (New Zealand) considered the empirical shortcomings of the CAPM, such as that the traditional version may systematically understate (overstate) the returns of low (high) beta companies. In consideration of these shortcomings, the AER (Australia) used the Black CAPM to inform the equity beta estimate in order to mitigate this bias (Australian Energy Regulator, 2013b).

The NZCC (New Zealand) noted that this bias may result from variables being excluded from the CAPM, such as size and book-to-market values. This implies that the FF3F model would be more appropriate. However, they did concede that it may also result from serious methodological issues with undertaking tests of the CAPM, or the difficulty of observing the market portfolio (Regulation Branch Commerce Commission, 2010a). A number of submissions to the NZCC (New Zealand) requested an ad-hoc adjustment to be made to the cost of equity estimate derived from the Simplified Brennan-Lally CAPM estimate to adjust for the possibility that the CAPM understates the cost of equity on low beta stocks. The NZCC (New Zealand) decided not to make such an adjustment as there is difficulty in assessing whether it is justified and also noted difficulty in assessing the size of the adjustment. The NZCC (New Zealand) considered including small company premiums or the Black CAPM to mitigate for this bias but chose not to (Regulation Branch Commerce Commission, 2010a).

ANEEL (Brazil), the UKCC (UK) and the NZCC (New Zealand) also discussed the simplifying assumptions of the CAPM, but still chose to use the model to estimate the cost of equity (Carvalho & Gabardo, 2013; Competition Commission, 2014b; Regulation Branch Commerce Commission, 2010a). Mr Nkadimeng (Nkadimeng, Interview) noted that all of the cost of equity models have some shortcomings, and that the selection of the CAPM is due to its widespread use among regulators.

CERC (India) considered using the CAPM as per submissions to it, however it concluded that there is not sufficient data to calculate the CAPM inputs, as very few of the Indian companies are listed on the primary market. As a result, CERC (India) did not use the CAPM to calculate its cost of equity (Central Electricity Regulatory Commission, 2014).

The UKCC (UK) considered the use of other models besides the CAPM, however they noted that the CAPM is the tool with the strongest theoretical underpinnings, it is not clear from academic literature that other models have better predictive power and none of the models overcomes the CAPM limitations of limited market data. The UKCC (UK) therefore consider the CAPM to be the most robust model to be used by regulators. Furthermore, the UKCC (UK) has used the CAPM in previous determinations and note that consistency and predictability in regulatory approach is in the public interest (Competition Commission, 2014b).

4.1.3. Simplified Brennan-Lally CAPM

The NZCC (New Zealand) uses the Simplified Brennan-Lally CAPM. In this model, the cost of equity is a function of the risk free rate and the tax-adjusted market risk premium (TAMRP) multiplied by the equity beta. The model is as follows:

$$k_e = r_f \times (1 - T_i) + \beta \times TAMRP$$

Where the T_i is the investors tax rate (Begg et al., 2013).

This is due to the fact that the traditional CAPM assumes that all forms of investment income, such as capital gains, interest and dividends, are all equally taxed. The Simplified Brennan-Lally CAPM was developed to incorporate the effect of New Zealand's imputation tax credit system and the general lack of tax on capital gains. The NZCC (New Zealand) adopts this version of the CAPM as it complies with the New Zealand tax system and it is widely used in New Zealand (Regulation Branch Commerce Commission, 2010a).

4.1.4. Black CAPM

The AER (Australia) considers that the empirical support for the Black CAPM is inconclusive. Furthermore, the sensitivity of the Black CAPM to its input parameters, as well as the difficulty in practice of its estimation, led to the AER (Australia) precluding its use to estimate the cost of equity capital. However, as the Black CAPM's estimate of the cost of equity capital will result in a higher estimate of the cost of equity for a low beta firm, the AER (Australia) decided to use the Black CAPM to inform its estimate of the equity beta (Australian Energy Regulator, 2013b). The NZCC (New Zealand) considered using the Black CAPM but determined that there is no clear evidence that the Black CAPM is a better predictor of the cost of equity and that it is not used in practice or by regulators (Regulation Branch Commerce Commission, 2010a). ANEEL (Brazil) also noted that the Black CAPM is not widely used by financial analysts (Carvalho & Gabardo, 2013).

4.1.5. International CAPM

ANEEL (Brazil) notes that it is not possible to use the local CAPM in Brazil as a result of the fact that there is not sufficient information, the capital markets are not sufficiently developed, there is limited diversification, low liquidity and the markets are very volatile. LEWA (Lesotho) also cites the lack of a sufficiently developed securities market as a factor for using the International CAPM. As a result, ANEEL (Brazil) and LEWA (Lesotho) use the International CAPM to calculate the cost of equity.

$$r_p = r_f + \beta \times (r_m - r_f) + r_B$$

Where $(r_m - r_f)$ is the reference market premium, r_f is the risk free rate in the reference market, β is the beta of the regulated sector and r_B is the country risk premium (Carvalho & Gabardo, 2013; Lesotho Electricity Authority, 2012).

4.1.6. Risk Premium model

The OEB (Canada) calculates its return on equity (ROE) for the purposes of the Fair Return Standard using a risk premium model. The OEB (Canada) did consider that multiple models should be used to directly and indirectly estimate the risk premium used, i.e. including the CAPM and other risk premium methods (Ontario Energy Board, 2009). Comments made to the OEB (Canada) stated that the estimate should place overwhelming weight on the CAPM. However, the OEB (Canada) was concerned that the CAPM did not adequately capture the inverse relationship between the ERP and the long term Canada bond yield (Ontario Energy Board, 2009).

The OEB (Canada) calculated its ROE parameters in 2009, and then annually adjusts the parameters selected based on changes in the forecasted bond yields and corporate spreads selected for the risk free rate (Ontario Energy Board, 2013). The adjustment formula is as follows:

$$ROE_t = ROE_{base} + 0.5 \times (LCBF_t - LCBF_{base}) + 0.5 \times (Utilbondspread_t - Utilbondspread_{base})$$

Where ROE_t is the ROE at time t , ROE_{base} is the ROE as determined in 2009 when the parameters and methodology were redetermined, $LCBF_t$ is the Long Canada Bond Forecast at time t , $LCBF_{base}$ is the Long Canada Bond Forecast as determined in 2009, $Utilbondspread_t$ is the 30 year A-rated utility corporate bond spread as determined at time t and $Utilbondspread_{base}$ is the 30 year A-rated utility corporate bond spread as determined in 2009⁷ (Ontario Energy Board, 2009).

The OEB (Canada) considered empirical evaluations from respondents that noted that the ROE of utilities change by between 45 and 55 basis points for every 100 basis point change in government bond yields. These empirical evaluations also determined that corporate bond yields have a statistically significant relationship with the cost of equity and therefore the OEB (Canada) also included these in the determination. The OEB (Canada) therefore selected an adjustment factor of 0.5 times. The OEB (Canada) did note that they will review the tariff calculation methodology every 5 years, implying a review in 2014 to be implemented from 2015 (Ontario Energy Board, 2009).

⁷ Refer to Ontario Energy Board (2009) for a more detailed methodology for the determination of LCBF and Utilbondspread.

CERC (India) considered calculating the cost of equity by adding a mark-up (premium) to an appropriate benchmark, such as the ten year government security rate. However, CERC (India) noted that as the debt market in India is not mature enough and is volatile, they do not believe that it is appropriate to link the rate of return to a benchmark until the debt market stabilises (Central Electricity Regulatory Commission, 2014).

4.1.7. Arbitrage Pricing Theory (APT)

ANEEL (Brazil) noted the existence of the APT model but did not consider it further (Carvalho & Gabardo, 2013). The UKCC (UK) considered whether the APT provided more accurate insights into the returns required by equity investors or to provide a cross-check for the CAPM. Although the UKCC (UK) did not provide further explanation regarding the reasons for their decision, they concluded that the CAPM is the most robust model to use for regulation and that it is not clear that other models have better predictive power, especially when applied to UK companies (Competition Commission, 2007).

4.1.8. Fama-French Three Factor (FF3F) model

The AER (Australia) considered the FF3F in detail and decided that it did not meet the majority of their requirements. Their evaluation concluded that the FF3F has no clear theoretical foundation to identify the risk factors, the empirical patterns on which the model was derived may be variable over time and may not be applicable in Australia, it is complex to implement and, to their knowledge, it is not widely used in Australia. Based on this analysis, they chose not to use the FF3F to calculate the cost of equity or to inform the inputs to the cost of equity (Australian Energy Regulator, 2013b).

The UKCC (UK) noted that it had considered whether the FF3F model provided more accurate insights into the returns required by equity investors or to provide a cross-check for the CAPM. Although the UKCC (UK) did not provide further explanation regarding the reasons for their decision, they concluded that the CAPM is the most robust model to use for regulation and that it is not clear that other models have better predictive power, especially when applied to UK companies (Competition Commission, 2007).

4.1.9. Other

The AER (Australia) also reviewed recent broker reports and established a range of the expected return on equity derived from those reports. The regulators also considered estimates of the required return on equity as calculated by other regulators to inform their estimate of the cost of equity. The AER (Australia) stated that limitations of using other regulators decisions, such as their decisions not reflecting current market conditions or based on different input methodologies, resulted in less weight being placed on these estimates (Australian Energy Regulator, 2013b).

CERC (India) uses a return on equity based approach to calculate the cost of equity. The methodology allows for a 70:30 split between debt and equity of the utility. The 30% equity is then multiplied by the post-tax ROE of 15.5% prescribed by CERC (India) (i.e. CERC (India) does not calculate a WACC). In order to incentivise producers to bring more capacity on line, CERC (India) allows an additional 0.5% for timely completion of projects (Central Electricity Regulatory Commission, 2014).

4.1.10. Summary of the cost of equity model used section

The CAPM is the preferred model of regulators surveyed based on its established theoretical underpinnings, its widespread use in regulatory decisions and the relative simplicity with which it can be implemented. The regulators did note the tendency of the CAPM to understate the cost of equity of low beta stocks. However, aside from the AER (Australia), the regulators did not adjust their CAPM derived cost of equity estimates based on this.

Therefore, NERSA's (South Africa) approach of using the CAPM is in line with international regulatory practice. It should be noted that although the CAPM is widely used, adjustments for risk factors, such as small stock premiums, are included in the CAPM derived cost of equity in practice (see PriceWaterhouseCoopers Corporate Finance, 2012). The CAPM has a strong conceptual underpinning but does not work in practice. In contrast, the FF3F model has a weak theoretical basis but has been found to provide better estimations of actual observed returns. Therefore, although NERSA's (South Africa) use of the CAPM is in line with international regulatory practice, it is submitted that it will come under increasing scrutiny as to whether it is the appropriate benchmark to be used by all regulators. Mr Nkadameng (Nkadameng, Interview) noted that all of the cost of equity models considered have some shortcomings, and that the selection of the CAPM is due to its widespread use among regulators.

The DCF model is the second most used model in the sample. However, the regulators noted limitations in its implementation in practice, such as a lack of reliable data and also the fact that the assumptions are inappropriate. Therefore, aside from PUCO (USA), the regulators which considered it preferred to use it as a cross-check for the equity risk premium.

The regulators that considered the FF3F model and the APT model did not consider that they were appropriate for use in regulation. Empirical studies have found that the FF3F model results in a greater estimate of the cost of equity, and has better explanatory power than both the CAPM and APT model (see Chrétien and Coggins (2011) and Schaeffler and Weber (2011)). The use of the FF3F model would result in cost of equity estimates up to 1.25% greater than the CAPM derived estimates (Wright et al., 2006). This finding indicates that regulators select the cost of equity model based on theoretical underpinnings and its relative simplicity of estimation in practice as opposed to empirical findings. This indicates that regulated firms are not being sufficiently compensated through the use of the CAPM model in regulatory determinations.

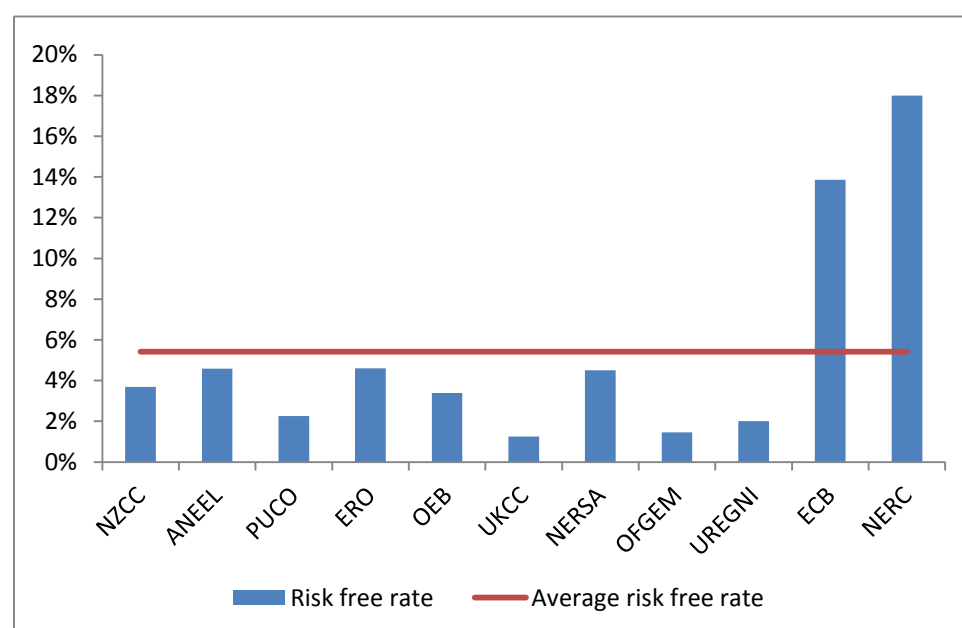
Also, a key factor in the selection of a model is consistency between regulatory periods as well as consideration of other regulators' decisions. It is therefore unlikely for regulators to select the FF3F model, given prior use of the CAPM as well as the fact that it is not widely used in practice.

4.2. Risk free rate

A summary of the risk free rate selections is shown in Table 4 and Graph 1⁸.

Regulator	Security	Country	Methodology year	Nominal/real	Term	Rf used
AER	Government securities	Australia	2013	Nominal	10 year	ND
LEWA	Government bonds	South Africa	2012	Nominal	10 year	ND
NZCC	Government bonds	New Zealand	2013	Nominal	3, 4 and 5 year	3.42%, 3.71% and 3.95% respectively
ANEEL	Government bonds	USA	2013	Nominal	10 year	4.59%
PUCO	Treasury bonds	USA	2013	Nominal	10 and 30 year	2.26%
ERO	Government bonds	Czech Republic	2009	Nominal	10 year	4.60%
OEB	Government bonds	Canada	2013	Nominal	10 and 30 year	3.40%
UKCC	Index linked gilt-yields	UK	2014	Real	Long term	1% to 1.5%
NERSA	Government bonds	South Africa	2013	Real	10 year	4.51%
OFGEM	British government securities	UK	2014	Real	5, 10 and 20 year	1.3% to 1.6%
UREGNI	Index linked gilt-yields	UK	2012	Real	3, 5 and 10 year	2%
ECB	Government bonds	South Africa	2001	Nominal	3 year	13.87%
NERC	Treasury bonds	Nigeria	2012	Nominal	10 year	18%
CERC	NA					
ND – Not Disclosed						
NA – Not Applicable						

Graph 1: Risk free rate comparison



For the purposes of Graph 1, the author has used the average where a range has been selected by the regulator. Only those regulators that have disclosed the risk free rate have been included in Graph 1.

⁸ The large difference between the ECB's (Namibia) and NERSA's (South Africa) risk free rate is due to the fact that ECB (Namibia) set their methodology in 2001, when interest rates were significantly higher (see Graph 2). Furthermore, The ECB (Namibia) used nominal risk free rates whereas NERSA (South Africa) used real risk free rates. ANEEL's (Brazil) risk free rate was calculated over the period 1995 to 2011, whereas PUCO (USA) estimated the risk free rate between 2011 and 2012, when interest rates were lower.

The risk free rate is commonly considered the least contentious decision which regulators need to make in assessing the cost of equity (see Aharonian, Villadsen and Vilbert (2010) and Jenkinson (2006, pg. 146-163)). Evidence of this can be seen in the summary of the regulators methodologies, with minimal variation on the methods used. The major points of difference in the selection relate to the term of the risk free selected, and the averaging period to be used.

4.2.1. Risk free proxy chosen

All of the regulators that use the CAPM based their assumption of the risk free rate on a government issued security. With the exception of the ECB (Namibia), LEWA (Lesotho) and ANEEL (Brazil), all of the regulators based the risk free rate on their local governments securities.

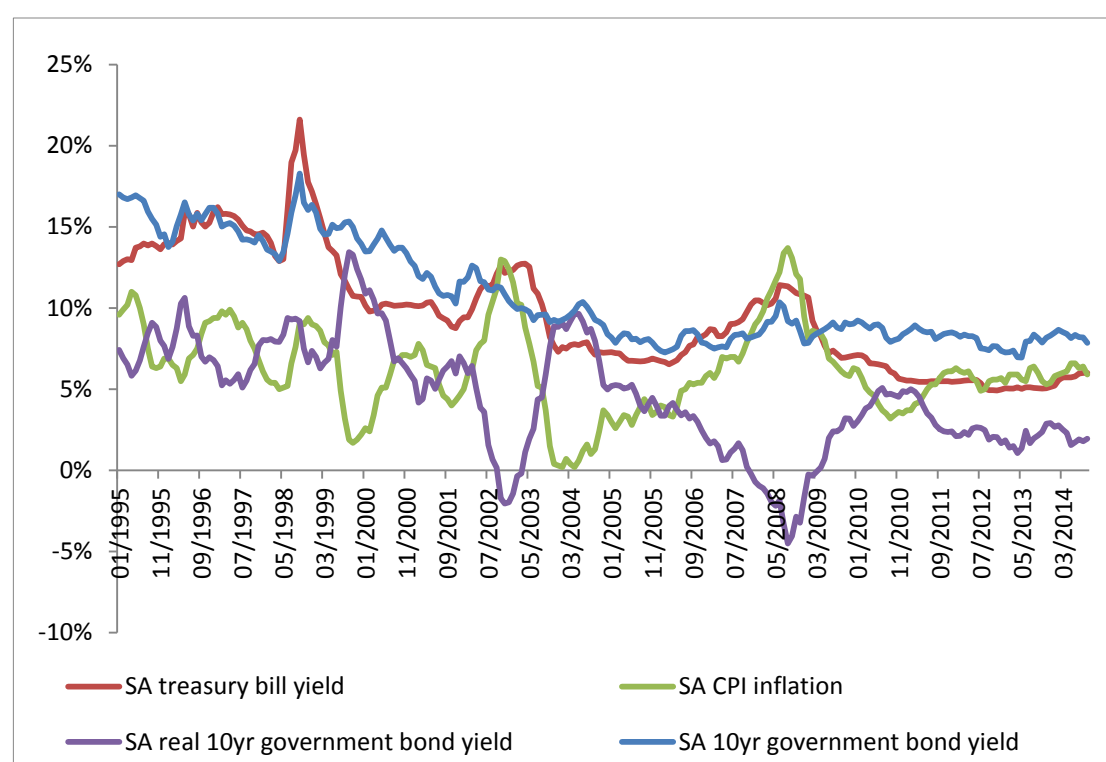
ANEEL (Brazil), and LEWA (Lesotho) based their risk free rate on a government security of the US and South Africa respectively, in line with their methodology to calculate the equity risk premium (Carvalho & Gabardo, 2013; Lesotho Electricity Authority, 2012). The ECB (Namibia) also used a South African government bond but did not provide a reason for this selection (Electricity Control Board, 2001). ANEEL (Brazil) notes that the Brazilian economy does not have a risk free asset. ANEEL (Brazil) considers that government bonds of developed economies are sufficiently risk free (Carvalho & Gabardo, 2013). It is interesting to note that the ERO (Czech Republic) (who also bases the ERP on the US) chooses to estimate the risk free rate based on Czech Republic government bonds. This is due to the fact that the ERO (Czech Republic) adjusts the US equity risk premium by the country risk premium instead of adjusting the CAPM cost of equity by the country risk premium (Energy Regulatory Office, 2009).

The NZCC (New Zealand) did consider that the yield on interest rate swaps could be used as they are used in practice. However, they concluded that this was primarily due to the lack of liquidity of government bonds post the global financial crisis, which no longer applies. Furthermore, they did not identify acceptance of this among academics or other regulators and therefore preferred government securities (Regulation Branch Commerce Commission, 2010a)

4.2.2. Term of the risk free rate used

The term of the risk free rate selected can have a significant impact on the cost of equity calculated. In South Africa, the premium between the short term government treasury bill rate and the 10 year government bond rate is 1.84%. This can be expected to increase the WACC on average, as the beta for a utility is normally below one. Graph 2 also highlights that risk free rates (both nominal and real) are at low levels compared to history. As a result, regulators need to consider whether current risk free rates would compensate the utilities over the term of the regulatory period.

Graph 2: South Africa 10 year bond yields and 91 day treasury yields vs CPI inflation: 1995 to 2014



Source: Statistics South Africa, South African Reserve Bank, Federal Reserve Bank of St. Louis

NERSA (South Africa), the ERO (Czech Republic), ANEEL (Brazil), LEWA (Lesotho), NERC (Nigeria) and the AER (Australia) all solely used ten year maturities in order to estimate the risk free rate (Australian Energy Regulator, 2013b; Carvalho & Gabardo, 2013; Energy Regulatory Office, 2009; Lesotho Electricity Authority, 2012; Nkadimeng, Interview; Nigerian Electricity and Regulatory Commission, 2012). Based on the sample, regulators prefer to use a bond with a ten year term in order to estimate the risk free rate. As there is normally an upward sloping yield curve, the use of a long term risk free rate will increase the cost of capital.

The AER (Australia) considered that the risk free rate should compensate for the risks faced over the regulatory period and therefore that a five year security should be chosen. However, they note that the issuance of debt is important for managing refinancing risk and that the average efficient energy network business issues debt every ten years. Furthermore, they considered the average maturity of the regulated firms which was seven years, supporting the ten year term (Australian Energy Regulator, 2013b). ANEEL (Brazil) also noted that the ten year term ties in with the long term investment profile of utilities (Carvalho & Gabardo, 2013).

In contrast, the NZCC (New Zealand) notes that the term of the risk free rate must be the same as the regulatory period. As a result, the NZCC (New Zealand) selects a five year term (unless the applicant requests a three or four year term). The NZCC (New Zealand) notes that due to the term structure of the yield curve, the regulated suppliers will either be compensated or undercompensated, depending on the term selected. Furthermore, in spite of submissions to the contrary, a longer period would over-compensate firms due to the use of interest rate swaps to manage refinancing risk and the re-pricing at the end of the regulatory period. As a result a five year period was selected (Regulation Branch Commerce Commission, 2010a).

UREGNI (Northern Ireland) estimated the risk free rate based on UK index linked gilt yields with maturities of three, five and ten years. However, UREGNI (Northern Ireland) did evaluate their estimate against other regulators' allowed risk free rate (UREGNI, 2012b). PUCO (USA) used the average of 10 and 30 year maturity government bonds. They did not provide further reason for the selection of the term (The Staff of the Public Utilities Commission of Ohio, 2013). The OEB (Canada) uses both 10 year and 30 year term bonds. They estimate the average premium of the 30 year bond yield over the 10 year yield over a one month period prior to the determination. This premium is then added on to the average of the consensus of the 3 month and 12 month 10 year bond yield, to obtain a "consensus" 30 year bond yield forecast (Ontario Energy Board, 2009).

OFGEM (UK) and the UKCC (UK) did not explicitly disclose the term of the risk free rate selected. However, they both considered a range of terms of government securities and made their evaluation based on that, as well as considering previously allowed rates (Competition Commission, 2014b; Nixon, 2014).

4.2.3. Averaging period selected

The averaging period was an element of dispersion among the regulators surveyed.

The AER (Australia) notes that a spot rate “on the day” would be the most theoretically correct solution. However, they choose a 20 consecutive business day averaging period, as close as possible to the start of the regulatory period, in order to ensure that the estimate is not exposed to unnecessary volatility (as would a spot estimate) and reflects current market conditions. Similarly, the NZCC (New Zealand) uses a one month averaging period. They go on further to say that they do not believe that long term averages are appropriate and are not consistent with the requirements of the CAPM (Australian Energy Regulator, 2013a; Regulation Branch Commerce Commission, 2010b).

There was little consistency identified between the regulators which used a longer term average for the risk free rate. NERSA (South Africa) estimated the risk free rate using a 25 year average of the yield on ten year government bonds. This corresponds with NERSA’s (South Africa) methodology requiring a 25 year sampling period to estimate the ERP (Nkadimeng, Interview; National Energy Regulator of South Africa, 2012). However, when interviewed, Mr Nkadimeng (Interview) noted that NERSA (South Africa) used the Credit Suisse Global Investment Returns Yearbook (2012) for the purposes of estimating its ERP. This results in a mismatch, as the ERP is based on a 111 year period (see section 4.3.1.2) compared to the 25 year average used for the risk free rate, which is contrary to the theoretical recommendations of Damodaran (2014).

The ERO (Czech Republic) and PUCO (USA) use a 12 month averaging period to estimate the risk free rate (Energy Regulatory Office, 2009; The Staff of the Public Utilities Commission of Ohio, 2013). OFGEM (UK) considered five year averages of the rate on their risk free rate proxies (Nixon, 2014). ANEEL (Brazil) calculated the risk free rate as an arithmetic average of US 10 year government bonds between 1995 and 2012 (Carvalho & Gabardo, 2013).

UREGNI (Northern Ireland) evaluated the risk free rates from 2001 until 2011 and noted that yields, since the 2008 global financial crisis and subsequent quantitative easing, have been kept artificially low. They therefore believe that the yield on government yields post 2008 is not an appropriate proxy for the risk free rate and includes almost no information as to the yields investors expect to earn. They therefore calculated the risk free rate as the ten year average rate pre-2008 (First Economics, 2011).

4.2.4. Other regulators decisions

UREGNI (Northern Ireland), OFGEM (UK), the UKCC (UK) also compared their estimate of the risk free rate to other regulators decisions as a check on their calculated risk free rate (Competition Commission, 2014b; Nixon, 2014; UREGNI, 2012b).

4.2.5. Summary of the risk free rate section

As noted by Aharonian, Villadsen and Vilbert (2010) and Jenkinson (2006, pg. 146-163), the risk free rate showed minimal disparity between the methodologies used by the regulators surveyed. All of the regulators which estimated a risk free rate used government securities as the proxy for the risk free rate. Furthermore, then of the 14 regulators surveyed considered ten year bonds, with this being the preferred maturity for the risk free rate.

NERSA's (South Africa) methodology for calculating the risk free rate is in line with regulatory practice. The CAPM is a single-period model, there is therefore a theoretical underpinning to using short-term rates for the risk free rate. However, in practice it appears that long-term risk free rates are selected. Therefore, although NERSA (South Africa) is consistent with international regulatory practice, although it may not be consistent with theory.

It must be noted that NERSA (South Africa) uses a 25 year average of historical yields on ten year government bonds. In an environment of historically low nominal and real interest rates (See Graph 2), NERSA (South Africa) may be overcompensating Eskom by using historical estimates. Furthermore, this averaging period to estimate the risk free rate does not correspond to the sampling period used to estimate the ERP selected (1900 to 2011), which is contrary to the recommendations of Damodaran (2014).

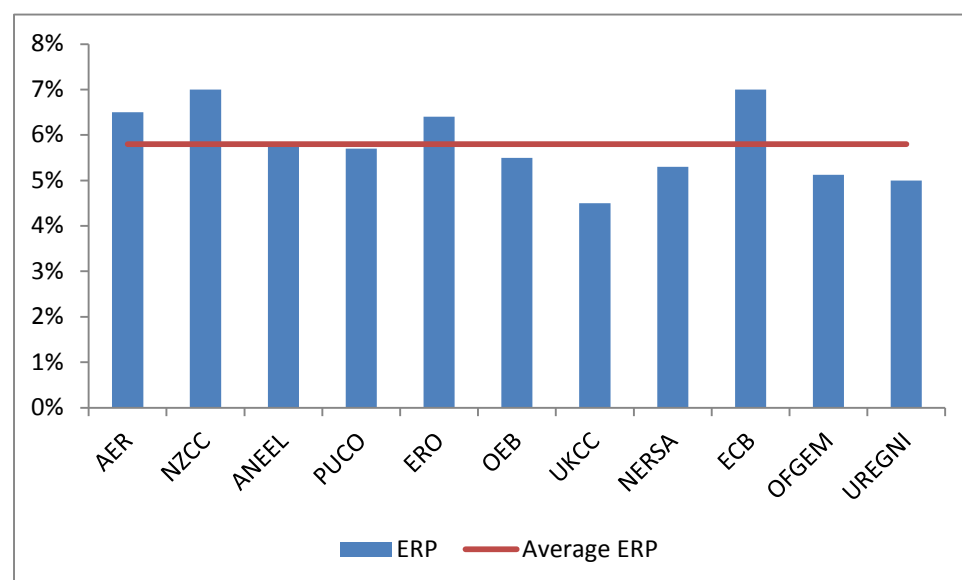
4.3. Equity risk premium (ERP)

A summary of the equity risk premium selections is shown in Table 5⁹ and Graph 2.

Regulator	MRP	Country	Method
AER	6.5% [Range 5% to 7.5%]	Australia	Historic, informed by DCF
LEWA	ND	South Africa	Historic, based on the JSE TOP40 index
NZCC	TAMRP 7%	New Zealand	Combination of ex-ante and ex-post methods
ANEEL	5.79%	USA	Historic
PUCO	5.70%	USA	Historic
ERO	5% plus CRP of 1.4%	USA	Historic, adjusted for investors future risk expectations
OEB	5.50%	Canada	Range of models, both ex-ante and ex-post
UKCC	4% to 5%	UK	Ex-post and ex-ante approaches, with forward looking estimates as a cross check
NERSA	5.30%	South Africa	Historic
ECB	7%	Australia and New Zealand	Regulators' decisions
OFGEM	4.75% to 5.5%	United Kingdom	Combination
UREGNI	5% [4.5% to 5%]	Northern Ireland	Regulators' decisions
NERC	NA	NA	NA
CERC	NA	NA	NA

ND – Not Disclosed
NA – Not Applicable

Graph 3: Equity risk premium comparison



⁹ The ERO (Czech Republic) calculates the ERP as the USA ERP plus a Czech Republic country risk premium. NERC (Nigeria) did not disclose the ERP selected. However, based on the cost of equity of 29% selected and the risk free rate of 18%, the ERP can be assumed to be approximately 11%. NERC (Nigeria) did not calculate a beta, and the author has therefore assumed a beta of one for this estimation.

For the purposes of Graph 3, the author has used the average where a range has been selected by the regulator. Only those regulators that have disclosed the equity risk premium have been included in Graph 3.

The lack of consistency identified among regulatory methodologies with regards the ERP indicates the extent of the difficulty in assessing this input into the cost of equity capital. This is therefore an area of judgement for the regulators, upon which regulated firms could contest the decision. However, there is a preference for historic methods of calculating the ERP. Of the 14 regulators surveyed, ten either based their decision on historical estimates or considered historical estimates in conjunction with other approaches.

The ERPs chosen ranged from 4% (UKCC (UK)) to 7% (NZCC (New Zealand)), with little differentiation between emerging market countries and developed markets in the ERP. The author does note that given NERC's (Nigeria) cost of equity of 29% and risk free rate of 18%, it's implied ERP is 11%. The methods used to estimate the ERP and the regulators considerations are discussed in the following section.

4.3.1. Using historic premiums

Historic estimates of the cost of equity capital proved to be the most widely used by the regulators in the sample. NERSA (South Africa), LEWA (Lesotho), PUCO (USA), the ERO (Czech Republic) and ANEEL (Brazil) only used historic estimations of the ERP while OFGEM (UK), the UKCC (UK), the AER (Australia), the OEB (Canada) and the NZCC (New Zealand) used historical estimates in combination with other methods (Australian Energy Regulator, 2013b; Begg et al., 2013; Carvalho & Gabardo, 2013; Competition Commission, 2014b; Energy Regulatory Office, 2009; Lesotho Electricity Authority, 2012; National Energy Regulator of South Africa, 2013; Nixon, 2014; The Staff of the Public Utilities Commission of Ohio, 2013). This is based on the assumption that recent historical estimates are an indicator of ex-ante rates.

The AER (Australia) notes that historic premiums have advantages in a regulatory context as they are transparent, the estimation methods have been extensively studied, the results are understood and this approach is widely used and has support as the benchmark method. The AER (Australia) notes that although it is not a forward looking method, as the estimate changes slowly over time, it is likely to reflect prevailing market conditions if investors' expectations of the forward looking premium are informed by historical excess returns. The AER (Australia) also references studies which have shown that there are problems which may result in biases in the historic method resulting from survivorship bias, unanticipated inflation, transaction costs, a historical lack of low cost opportunities for diversification and the inclusion of historical data which includes recessions (such as Dimson, Marsh and Staunton (2000)) (Australian Energy Regulator, 2013b).

The NZCC (New Zealand), OFGEM (UK) and the UKCC (UK) note that there are queries as to whether the historical estimate is an accurate predictor of the future. This is due to the fact that prominent financial experts (such as Dimson, Marsh and Staunton (2000) and Siegel (2005)) note that using historical rates is likely to overstate the future return (The Office of Gas and Electricity Markets, 2013). Also, the UKCC (UK) notes that the realised equity premiums are higher than can be explained by standard economic models (as described by Mehra and Prescott (1985))(Competition Commission, 2014b). As a result, the NZCC (New Zealand) uses a range of methods (Regulation Branch Commerce Commission, 2010a).

LEWA (Lesotho), the ERO (Czech Republic) and ANEEL (Brazil) use the International CAPM, and therefore estimate their ERP based on an international proxy market. This is due to the fact that their home markets are not deemed to be sufficiently developed to be used to estimate the ERP directly. This is then adjusted for a country risk premium (refer to section 4.3.6.2) (Carvalho & Gabardo, 2013; Energy Regulatory Office, 2009). Although LEWA (Lesotho) notes that South Africa has different economic characteristics and risks conditions, they conclude that there exists a number of common factors between the two countries and South Africa offers market depth and liquidity far exceeding any country in the region (Lesotho Electricity Authority, 2012).

4.3.1.1. Use of other sources

A number of regulators used ERP estimates as published by respected sources or considered the views of respected sources in evaluating their estimate. Sources used were primarily publications by Dimson, Marsh and Staunton¹⁰ (NERSA (South Africa), AER (Australia), the UKCC (UK), OFGEM (UK), and the NZCC (New Zealand)), Damodaran (AER (Australia), ANEEL (Brazil) and the ERO (Czech Republic), Ibbotson Associates (the NZCC (New Zealand) and PUCO (USA)), Siegel (AER (Australia), the NZCC (New Zealand) and the UKCC (UK)) and Fama and French (the UKCC (UK) and the ERO (Czech Republic)). The use of published sources increases the transparency and the ability of the model to be replicated (Australian Energy Regulator, 2013b; Begg et al., 2013; Carvalho & Gabardo, 2013; Competition Commission, 2014b; Energy Regulatory Office, 2009; Nixon, 2014; Nkadameng, Interview; The Staff of the Public Utilities Commission of Ohio, 2013).

4.3.1.2. Sampling period used

The sampling period used to estimate the ERP can have an impact on the value which is calculated, as the ERP is not static over time. As an example, Dimson, Marsh and Staunton (2001) show that the real return on equities in the UK between 1900 and 2000 was 5.8%, while it was 8.2% between 1955 and 2000. Therefore the selection of the period can have an effect on the final ERP used in the regulatory decision. Per the sample, the regulators preferred to use longer term periods in the determination, however the benefits of more recent information was debated.

The AER (Australia), the UKCC (UK), the NZCC (New Zealand), ANEEL (Brazil) and OFGEM (UK) (in previous determinations) noted that a longer sampling period provides a greater number of observations and so provides a more statistically precise estimate, which increases the transparency of the cost of equity (Australian Energy Regulator, 2013b; Carvalho & Gabardo, 2013; Competition Commission, 2007; The Office of Gas and Electricity Markets, 2013). Also, over long periods of time, periods where the ERP exceeds investors' expectations would set off against periods where the ERP is below investor expectations, resulting in an estimate of what the average investor would expect (Regulation Branch Commerce Commission, 2010a).

¹⁰ Dimson, Marsh and Staunton are the authors of the Credit Suisse Global Investment Returns Yearbook series

However, the AER (Australia) and OFGEM (UK) also considered that more recent periods have better quality data and are more likely to reflect the current financial environment. Given this, OFGEM (UK) changed their methodology recently to give more weight to current market conditions, given low interest rates since the credit crunch (Australian Energy Regulator, 2013b; Nixon, 2014).

The AER (Australia) preferred to use a combination of periods as shorter periods are more likely to be affected by the current state of the business cycle and one off events. Therefore, as all periods have advantages and disadvantages, with no single period being deemed superior, the AER (Australia) uses a range of periods in the calculation (Australian Energy Regulator, 2013b). ANEEL (Brazil) and the ERO (Czech Republic) only used a long term sampling period (starting from 1928) (Carvalho & Gabardo, 2013; Energy Regulatory Office, 2009).

The NERSA (South Africa) methodology for the ERP requires a 25 year historical average to estimate the ERP (National Energy Regulator of South Africa, 2012). However, Mr D. Nkadimeng (Interview) stated that NERSA (South Africa) used 5.3% based on the findings of the Credit Suisse Global Investment Returns Yearbook (Credit Suisse Research Institute, 2012). The Credit Suisse Research Institute (2012) shows an ERP for stocks over treasury bonds of 5.3% for the period 1900 to 2011, implying a 111 year period selected by NERSA (South Africa). This may result in additional regulatory risk and reduce the transparency of the regulatory process, as the sampling period used in the MYPD 3 process does not agree with its published methodology.

4.3.1.3. Method of averaging

This was not disclosed by LEWA (Lesotho) and was not considered by UREGNI (Northern Ireland) (Lesotho Electricity Authority, 2012; UREGNI, 2012b).

The selection of the method of averaging can have a material effect on the ERP, as the arithmetic mean can be more than 2% greater than the geometric mean. The selection of the arithmetic mean is therefore more favourable from the perspective of the regulated firm. The UKCC (UK) chose estimates at the higher end of the range in order to be more favourable to the supplier. This was due to the fact that they believed that the consequences of lower returns (resulting in lack of investment) outweighed the additional cost to be borne by the consumer (Competition Commission, 2014b). However, as noted by OFGEM (UK) and the ERO (Czech Republic), there is little consensus among regulators and in practice on which is the most appropriate to use (Energy Regulatory Office, 2009; The Office of Gas and Electricity Markets, 2013).

The UKCC (UK), PUCO (USA), ANEEL (Brazil) and the NZCC (New Zealand) used an arithmetic average (Competition Commission, 2014b; The Staff of the Public Utilities Commission of Ohio, 2013). The NZCC (New Zealand) makes this decision as it states that the arithmetic average generates an ERP that is more likely to correspond with the initial value of the investment, whereas the geometric mean will result in a value less than the initial value of the investment. The NZCC (New Zealand) also states that the arithmetic mean is preferred by most regulators (Regulation Branch Commerce Commission, 2010b). The AER (Australia) and ANEEL (Brazil) both stated that the arithmetic average will likely be an unbiased estimator of the forward looking ten year ERP. The AER (Australia) goes further to state that the mean is based on an average of one year returns and that, as one year returns are variable, the arithmetic average will likely overstate the estimate of the ERP whereas the geometric average will understate the estimate of the ERP (Australian Energy Regulator, 2013b). ANEEL (Brazil) notes that the arithmetic mean is more likely to be in line with the requirements of the CAPM (Carvalho & Gabardo, 2013).

In contrast to this, NERSA (South Africa) and the ERO (Czech Republic) both used the geometric mean. Their methodologies did not provide further evidence regarding the reason for the selection (Energy Regulatory Office, 2009; National Energy Regulator of South Africa, 2013).

The UKCC (UK), OFGEM (UK) and the AER (Australia) considered both arithmetic and geometric means in their determination. The UKCC (UK) also considered the Blume unbiased estimator which results in a weighted average of the arithmetic and the geometric mean. This is in line with AER's (Australia) comment that the best estimate of the ERP is likely to be between the arithmetic and geometric mean (Australian Energy Regulator, 2013b; Competition Commission, 2014b; Nixon, 2013).

4.3.2. DCF model

NERSA (South Africa), LEWA (Lesotho), ANEEL (Brazil), the ERO (Czech Republic), PUCO (USA), the NZCC (New Zealand) and UREGNI (Northern Ireland) did not use the DCF model in estimating the ERP (Carvalho & Gabardo, 2013; Energy Regulatory Office, 2009; National Energy Regulator of South Africa, 2012; The Staff of the Public Utilities Commission of Ohio, 2013; UREGNI, 2012b). The NZCC (New Zealand) notes a number of limitations with the DCF model, as discussed in section 4.1.1. As a result, the NZCC (New Zealand) chooses to use survey evidence in order to obtain ex-ante estimates of the ERP (Regulation Branch Commerce Commission, 2010b).

The ERO (Czech Republic) considered using ex-ante estimates of the ERP such as the DCF model, but noted that this can result in highly volatile estimates which can be negative in

certain phases of the economic cycle. The ERO (Czech Republic) therefore used historical estimates of the ERP. These estimates were selected from information published by Damodaran, which had adjusted the ERP for investor's risk expectations going forward (Energy Regulatory Office, 2009).

The UKCC (UK) and the AER (Australia) both chose to use the DCF model to inform their estimates of the ERP, as opposed to using it as a model to determine the cost of equity directly. The AER (Australia) does not consider DCF estimates to be as robust as the historical average method but they do consider the estimates useful. This is due to the fact that the DCF model is a theoretically sound model of estimation and is also a forward looking model. Also, as it is based on prevailing market prices, it is likely to incorporate current market conditions (Australian Energy Regulator, 2013b; Competition Commission, 2014b).

However, the DCF estimates are very sensitive to assumptions made and as a result their major concerns are with the long term growth rate and the time it takes to reach the long term growth rate. As a result of this sensitivity, the AER (Australia) uses both a two-stage and a three-stage DCF model and also uses a range of assumptions (Australian Energy Regulator, 2013b). The model implemented by the AER (Australia) is discussed in section 4.1.1 .

The UKCC (UK) used the DCF model as a cross-check for their calculation of the ERP. However, they did note that it is necessary to make an assumption for the long term growth rate. Given that the DCF is based on the current market conditions, short run forecasts would be more appropriate to calculate a short run ERP. However as the UKCC (UK) is interested in the long term ERP, they placed less weight on the results of the DCF model. The UKCC (UK) used a DCF model where the long term growth assumption was based on the long term potential economic growth. However, they view this as an arbitrary assumption and see empirical support for the long term dividend growth being lower than long term economic growth. They also noted that this model is subject to analysts' optimism bias (Competition Commission, 2014b).

4.3.3. Survey evidence

NERSA (South Africa), LEWA (Lesotho), PUCO (USA), UREGNI (Northern Ireland), CERC (India), ANEEL (Brazil) and the ERO (Czech Republic) did not consider the evidence of surveys in their estimation of the ERP (Central Electricity Regulatory Commission, 2014; Energy Regulatory Office, 2009; Lesotho Electricity Authority, 2012; National Energy Regulator of South Africa, 2013; The Staff of the Public Utilities Commission of Ohio, 2013; UREGNI, 2012b).

The AER (Australia), OFGEM (UK) and the NZCC (New Zealand) did consider the evidence of surveys in forming their estimate of the ERP. They note that as the ERP is a forward looking estimate, it is reasonable to estimate it using investor's expectations (Australian Energy Regulator, 2013b; Nixon, 2014; Regulation Branch Commerce Commission, 2010a).

The AER (Australia), OFGEM (UK), the NZCC (New Zealand) and the UKCC (UK) all noted the limitations implicit in survey evidence. The survey may be biased by non-response bias, the structure of the survey, in terms of the types of questions asked, the wording of the questions and the sample of respondents selected. The surveys are also generally taken sporadically and may therefore not reflect current market conditions (Australian Energy Regulator, 2013b; Competition Commission, 2014b; Regulation Branch Commerce Commission, 2010a). Furthermore, surveys do not clarify the time frame of the parameters which are estimated, which averaging method should be used or whether the ERP should be over bills or bonds. Given these limitations, the UKCC (UK) prefers to base their ERP on the underlying data upon which the respondents would supposedly base their views and chooses not to use survey data (Competition Commission, 2014b). OFGEM (UK) also noted that they do wish to minimise dependence on subjective evidence (Nixon, 2014).

The OEB's (Canada) method of determining the ERP is essentially a survey based approach. Stakeholders in the determination of the premium submitted their estimates of the ERP to the OEB (Canada), based on a variety of models (such as DCF, CAPM, regulatory decisions and other econometric models). The OEB (Canada) then used a simple average of the six participants' ERP estimates (Ontario Energy Board, 2009). The NZCC (New Zealand) also conducted a similar survey, however they noted that the sample was very small and also not representative of the range of views on the prevailing ERP. The NZCC (New Zealand) therefore did not consider such a survey to be a good indicator of the ERP (Regulation Branch Commerce Commission, 2010a)

4.3.4. Conditioning variables

Conditioning variables are variables which can be used to make adjustments to the mean historical ERP. The ERO (Czech Republic) uses estimates of the ERP as published by Damodaran, who adjusts the equity risk premium for investors' future expectation of risk (Energy Regulatory Office, 2009). The AER (Australia) considered dividend yields, credit spreads and implied volatility to be used as conditioning variables (Australian Energy Regulator, 2013b).

4.3.4.1. Dividend yields

The fourth method to calculate the ERP which the AER (Australia) considers is based on dividend yields. They note that there is theoretical support for this method (see Fama and French (1988)), although they do conclude that the majority of this evidence is for the use of dividend yields informing the ERP. OFGEM (UK) considered dividend yields in order to inform their estimate of the ERP (Nixon, 2013). The AER notes that dividend yields have advantages for use in regulation as they reflect current market conditions, are comparable and timely. However, they are difficult to implement in practice. They therefore use the dividend yield method as a directional indicator for the cost of equity (Australian Energy Regulator, 2013b).

4.3.4.2. Credit spreads

The AER (Australia) notes that changes in credit spreads may offer evidence regarding changes in the ERP. The AER (Australia) continues by stating that it is difficult to convert credit spreads into a quantitative estimate of the cost of equity. However, credit spreads change daily and may therefore reflect prevailing market conditions. As a result, they use it as additional information in order to calculate the estimate of the ERP (Australian Energy Regulator, 2013b).

4.3.4.3. Implied volatility

The AER (Australia) considers implied volatility as being fit for purpose in estimating the ERP. In spite of this, there are limitations on this evidence and difficulties in implementing it in practice. However, implied volatility changes daily and may therefore reflect prevailing market conditions. In spite of this, the AER (Australia) intends to give this method limited consideration based on their concerns with the robustness of this evidence (Australian Energy Regulator, 2013b)

4.3.5. Other regulators' decisions

The AER (Australia), the OEB (Canada), the UKCC (UK), the NZCC (New Zealand), OFGEM (UK) and UREGNI (Northern Ireland) assessed their estimates of the equity risk premium against those of other regulatory decisions. LEWA (Lesotho) methodology allows for comparisons against cost of equity estimates as determined by NERSA (South Africa). These regulators (with the exception of UREGNI (Northern Ireland)) do not rely on other regulators' allowed ERP but rather use that as a cross-check for their own estimates (Australian Energy Regulator, 2013b; Competition Commission, 2014b; Lesotho Electricity Authority, 2012; Nixon, 2014; Ontario Energy Board, 2009; Regulation Branch Commerce Commission, 2010b; UREGNI, 2012b).

UREGNI's (Northern Ireland) decision was purely based on the range of equity market returns as calculated by other regulators. This was due to the fact that there is no consensus on the methodologies used to calculate the ERP, and therefore the ERP used should be in line with other regulators' decisions. The decision considered the ranges of equity market returns which had been calculated by OFGEM (UK) and the UKCC (UK), in determining a range of equity market returns of 6.5% to 7%, implying an equity risk premium of 4.5% to 5%. The ERP of 5% was selected as it is more in line with the 5.25% used by OFGEM (UK) (First Economics, 2011; UREGNI, 2012a). The ECB (Namibia) also only considered the results of other regulators decisions, using Australia and New Zealand. No further explanation as to the reasons for the regulators selected was given (Electricity Control Board, 2001).

4.3.6. Adjustments made to the ERP

Both the AER (Australia) and the NZCC (New Zealand) adjusted the ERP by 0.5% in order to compensate for the effect of the global financial crisis (Australian Energy Regulator, 2013b; Begg et al., 2013). The OEB (Canada) included an upward adjustment of the ERP of 0.5% in order to compensate for transaction costs (Ontario Energy Board, 2009).

4.3.6.1. Other premiums

Submissions to the NZCC (New Zealand) requested that a small company premium be added on to the cost of equity estimate as derived using the Simplified Brennan-Lally CAPM, based on the relative size of the regulated firm. The aim of this was to adjust for the propensity of the CAPM to understate the returns of low beta stocks and the small firm effect. The NZCC (New Zealand) concluded that the evidence relating to the small company premium effect was inconclusive. Furthermore, they note that additional costs incurred by a firm as a result of having a lower market capitalisation should not be borne by the consumer. This would be against the requirements of their Act. Therefore the NZCC (New Zealand) did not allow a small company premium (Begg et al., 2013).

4.3.6.2. Country risk premiums

Table 6: Country risk premiums		
Regulator	Include a country risk premium?	Premium calculated
AER	No	
LEWA	Yes	Not disclosed
ANEEL	Yes	3.52%
UREGNI	No	
UKCC	No	
NZCC	No	
ERO	Yes	1.40%
OEB	No	
NERSA	No	
NERC	No	
ECB	No	
OFGEM	No	
PUCO	No	
CERC	No	

LEWA (Lesotho), the ERO (Czech Republic) and ANEEL (Brazil) include a country risk premium onto the CAPM. This is due to the fact that the other components of the CAPM are based on countries other than their local market. As a result, the country risk premium is used to reflect the different country-specific risk factors between their local market and the comparator country (Carvalho & Gabardo, 2013; Energy Regulatory Office, 2009; Lesotho Electricity Authority, 2012).

LEWA (Lesotho) calculates the country risk premium as the difference between the spread on the longest duration Government of Lesotho treasury bills and the Republic of South Africa Government bonds of a similar duration. The Lesotho government's treasury bills are issued for a period of 364 days (Lesotho Electricity Authority, 2012).

ANEEL (Brazil) considered calculating the country risk premium based on the relative sovereign rating of Brazil as published by the three ratings agencies (Fitch, Moody's and Standard and Poor's). However, ANEEL (Brazil) chose to calculate the country risk premium by using the Emerging Markets Bond Index Plus Brazil as published by J.P. Morgan. This is due to the fact that this is more transparent and is widely used in the market. This index is quoted as the spread of interest rates of the local currency over US government bonds of the same duration (Carvalho & Gabardo, 2013).

The ERO (Czech Republic) used the country risk premium of 1.4% as published by Aswath Damodaran. This premium is included in the ERP as opposed to being added on as a separate factor in the CAPM (as per the method of ANEEL (Brazil) and LEWA (Lesotho)). As a result it is multiplied by the beta in the calculation of the cost of equity (Energy Regulatory Office, 2009).

In its application to UREGNI (Northern Ireland), Northern Ireland Electricity Ltd. (NIE Ltd.) included a Northern Ireland premium of 1% to be added onto the CAPM estimate. UREGNI (Northern Ireland) did not consider it appropriate to include a Northern Ireland country premium (UREGNI, 2012b). The UKCC (UK) also did not allow the country risk premium when it considered NIE Ltd.'s appeal as it considered that the standard CAPM resulted in a fair return being allowed (Competition Commission, 2014b).

Nampower applied for a country risk premium of 3% in its application to the ECB (Namibia). The ECB (Namibia) chose not to include a country risk premium on the ERP as Nampower is a state owned entity, with the government as its shareholder. The ECB (Namibia) stated that as the government can effectively control country risk, it would not be appropriate to compensate it for this risk (Electricity Control Board, 2001).

4.3.7. Summary of the equity risk premium section

The historical method of estimating the equity risk premium is the most widely used method among the regulators surveyed. Furthermore, a preference for the arithmetic method of averaging was identified from the sample.

Therefore, NERSA's (South Africa) selection of using the historical equity risk premium is in line with the methodologies of international regulators. However, regulators in developed economies estimate the equity risk premium based on a range of methodologies, including ex-post and ex-ante methods, such as the DCF or survey methods. These methods tend to be used to inform the historical estimate of the equity risk premium.

As a result, regulators that estimate an historical ERP, including NERSA (South Africa), may overstate the estimate of the equity risk premium going forward given that the historically realised equity risk premiums will likely exaggerate investor's current required equity risk premium (see Dimson, Marsh and Staunton (2000) or Arnott and Bernstein (2002)).

Furthermore, NERSA's (South Africa) use of geometric averaging is not in line with the regulators surveyed. Given the fact that this may result in an understatement of the equity risk premium of more than 2%, this may result in an understatement of the cost of equity estimated. This will have the effect of undercompensating Eskom in its tariff determinations. However, it should be noted that Damodaran (2010) recommends the use of a geometric mean when considering a longer term horizon. NERSA's (South Africa) approach therefore appears to have a theoretical foundation.

NERSA's (South Africa) published methodology for estimating the ERP requires a 25 year sampling period to be used. However, this study found that NERSA (South Africa) estimates its ERP based on the Credit Suisse Research Institute's (2012) estimate of the ERP, which uses a 111 year sampling period. This reduces the transparency of the regulatory process which may result in an increase in regulatory risk. Furthermore, NERSA (South Africa) may not be appropriately compensating Eskom as a result.

4.4. Equity beta

A summary of the equity beta selections is shown in Table 7¹¹.

Table 7: Equity Beta														
Regulator	AER	NERC	LEWA	NZCC	ANEEL	ECB	PUCO	ERO	OEB	UKCC	NERSA	UREGNI	CERC	OFGEM
Asset Beta	0.44	NA	ND	0.34	0.44	Gx: 0.5 Tx: 0.25 Dx: 0.35	ND	DSO: 0.35 TSO: 0.3	ND	0.35 to 0.4	0.294	0.42	NA	0.38
Debt beta	0	NA	ND	0	0	0	ND	0	ND	0.05	0	0.1	NA	0.1
Equity beta	0.7 [range 0.4 to 0.7]	NA[4]	ND	0.61	0.92	ND	0.64	DSO: 0.54 TSO: 0.4	ND	0.6 to 0.7	0.84	0.9	NA	0.9
Gearing	60%	70%	ND	44%	62.33%	50%	46.70%	TSO: 30% DSO: 40%	60%	45%	65%	60%	70%	65%
ND – Not Disclosed NA – Not Applicable														

¹¹ The ECB (Namibia) methodology showed separate asset betas for generation (Gx), transmission (Tx) and distribution (Dx). Estimated the implied asset beta for AER (Australia) and NERSA (South Africa) based on equity beta, gearing and leveraging formula used. NERC (Nigeria) chose not to calculate an equity beta, preferring to estimate it at the next tariff period. Estimated the implied equity beta for the ERO (Czech Republic) based on asset beta, gearing and leveraging formula used. The OEB (Canada) did not perform an evaluation of the equity beta. The OEB (Canada) obtain submissions from respondents on their estimates of the equity risk premium and calculated an average to use in their risk premium based model

The equity beta is a key determinant of the cost of equity capital for regulators. Regulators are faced with four major issues in deriving the beta estimates; these being what interval of return data to use, over how long a time period, whether to adjust the beta for mean reversion, and whether to estimate the beta using a portfolio or individual securities returns (Aharonian et al., 2010).

This section considers the regulators decisions relating to these issues, and other issues identified per the regulators methodologies.

4.4.1. Impact of regulatory system of beta

The AER (Australia) and UREGNI (Northern Ireland) performed a conceptual analysis of the systematic risk factors affecting the benchmark efficient energy utility. The AER (Australia) analysis considered that the nature of the regulatory regime will impact on the utility as regulation limits competition of the entity. The AER (Australia) and UREGNI (Northern Ireland) both noted that regulation (through revenue caps) mitigates the demand risk of the entity as it may adjust its price to ensure it maintains its revenue requirement and the selection of estimation methods and capital expenditure allowances in the regulatory methodology impacting on the cash flow profile (Australian Energy Regulator, 2013b; UREGNI, 2012b).

The AER (Australia), UREGNI (Northern Ireland) and NERSA (South Africa) concluded that an energy network firm would have a lower systematic risk exposure than the market (i.e. a beta less than one) resulting from lower business risk (Australian Energy Regulator, 2013b; National Energy Regulator of South Africa, 2012; UREGNI, 2012b). The AER (Australia) discussed this further, by considering that the lower business risk is a result of the fact that the firms operate as natural monopolies and provide essential services and so are subject to low price elasticity of demand. The regulatory structure also contributes to this low business risk through the form of pricing control, cost pass through mechanisms and tariff variation mechanisms.

UREGNI (Northern Ireland) also noted that regulated entities are subject to less cost risk. They performed a comparison of the systematic risk exposure of a Northern Ireland regulated entity in comparison to a conventional Great Britain regulated entity and determined that they would have a similar beta (UREGNI, 2012b).

The NZCC (New Zealand) noted that it may be necessary to adjust the betas of the overseas comparator companies due to differences in the regulatory system. This is due to the fact that in theory, the regulatory system can transfer the risk between the firm and the customer. For example, they note that the US rate of return regulation is a low powered regulatory environment and has a shorter regulatory period, allowing for quicker cost pass

through. In comparison, price-cap regulation (such as in the UK) and longer regulatory periods will result in the supplier bearing more of the cost increases. Therefore the NZCC (New Zealand) notes that as regulatory differences can affect the systematic risk of the firm, it has adjusted beta estimates upwards for US firms in the past. The NZCC (New Zealand) performed a thorough conceptual analysis of the differences between the UK, US and NZ regulatory regimes for its most recent methodology and deemed that no adjustment was necessary for differences between the regulatory regimes (Regulation Branch Commerce Commission, 2010a).

The AER (Australia) changed its regulatory methodology during 2013. The AER (Australia) noted that changes to the methodology may result in changes to the systematic risk profile of the regulated companies, however, they were unable to ascertain the impact their change in methodology would have as at the time of the determination (Australian Energy Regulator, 2013b). OFGEM (UK) also changed its methodology to give greater weight to contemporary evidence in their determinations. They considered that this may open the determinations up to more subjectivity and volatility and thereby increase regulatory risk. They noted concerns relating to those issues and that they are trying to minimise unnecessary regulatory risk. However, OFGEM concluded that ignoring current market conditions would also give rise to regulatory risk, which would be inconsistent (Nixon, 2014).

It is therefore apparent that the regulators do consider that regulation has an effect on beta by decreasing the risk exposure of the entity. The effect is reliant on the nature of the regulatory environment, including the cost pass through mechanisms, capital expenditure incentives and the extent of the exposure to demand variability. These factors should be considered by regulators when selecting proxy companies for their beta estimates.

4.4.2. Empirical analysis

Table 8: Comparison of empirical analysis methods			
Regulator	Comparator countries used	Estimation period	Data points
LEWA	ND	ND	ND
PUCO	US	5 years	Weekly
NZCC	US, Australia and New Zealand	5 years	Monthly
OEB	NA	NA	NA
CERC	NA	NA	NA
ERO	Luxembourg, Belgium, UK, Spain, Switzerland, Italy and Hungary	20 months	Monthly
ANEEL	US	5 years	Weekly
UREGNI	UK	2 years	ND
AER	Australia and UK	Multiple periods	Monthly and weekly
OFGEM	UK	2 years	Daily
NERSA	US	5 years	Weekly
NERC	NA	NA	NA
ECB	ND	ND	ND
UKCC	UK	2 years	Daily
NA – Not applicable			
ND – Not disclosed			

The primary method used to estimate the equity beta was the use of regression analysis. This is based on the assumption that the historic beta is an accurate predictor of the future beta. However, within this, regulators used different methods in the regression in terms of the data points chosen and estimation periods selected. Furthermore, a number of the regulators did not perform the regression analysis themselves but preferred the use of recognised sources of equity betas.

NERC (Nigeria) noted that electricity supply in Nigeria is not an area with any history of investment, and there is therefore not enough data from which to estimate a statistically significant beta. NERC (Nigeria) therefore did not calculate a beta (i.e. did not apply any value for the beta). This therefore implies a beta of one selected (Nigerian Electricity and Regulatory Commission, 2012).

4.4.3. Estimation period selected

The AER (Australia) notes that using older data might result in a less relevant estimate, whereas using a shorter period would result in a less statistically robust estimate. The NZCC (New Zealand), NERSA (South Africa), PUCO¹² (USA) and ANEEL (Brazil) use a 5 year period (Australian Energy Regulator, 2013b; Carvalho & Gabardo, 2013; Nkadimeng, Interview; Regulation Branch Commerce Commission, 2010b; The Staff of the Public Utilities Commission of Ohio, 2013). The NZCC (New Zealand) stated that it is intending on evaluating the time period, and the number of data points to be used in future.

The AER (Australia) notes that it is reasonable to use an estimation period of at least 5 years. The AER (Australia) therefore estimates the beta using a range of estimation periods including the longest period for which data is available, the last five years and the period between the technology bubble and the global financial crisis (Australian Energy Regulator, 2013b).

The ERO (Czech Republic) used 20 month beta coefficients (Energy Regulatory Office, 2009). The UKCC (UK), OFGEM (UK) and UREGNI (Northern Ireland) calculated beta based on a two year estimation period (First Economics, 2011; Nixon, 2014). The UKCC (UK) did note that betas can vary over time and therefore prefer the use of longer run estimates. As a result, the UKCC (UK) used rolling two year estimation periods between 2000 and 2011 to calculate the beta (Competition Commission, 2014b).

LEWA (Lesotho) did not prescribe the estimation period in their methodology (Lesotho Electricity Authority, 2012).

4.4.4. Portfolio

The AER (Australia) calculated the beta using a range of portfolio methods including equally weighted portfolios, value weighted portfolios and time varying portfolios (Australian Energy Regulator, 2013b). The majority of the regulators calculated the beta of each comparator firm individually, and then calculated an average of the asset beta estimates of the sample.

4.4.5. Data points

The two major studies on which the AER (Australia) consideration were based used both monthly and weekly data points in estimating the equity beta (Australian Energy Regulator, 2013b). The betas used by ANEEL (Brazil) and PUCO (USA)¹³ are based on weekly data points (Carvalho & Gabardo, 2013; The Staff of the Public Utilities Commission of Ohio,

¹² PUCO (USA) used Value Line betas which are based on weekly samples over five years (Money-Zine, 2014)

¹³ PUCO (USA) used Value Line betas which are based on weekly samples over five years (Money-Zine, 2014)

2013). The NZCC (New Zealand), NERSA (South Africa) and the ERO (Czech Republic) used monthly data points (Energy Regulatory Office, 2009; Nkadameng, Interview; Regulation Branch Commerce Commission, 2010b). The UKCC (UK) used daily data as it is likely to have the smallest standard error and is therefore more statistically robust (Competition Commission, 2014b). OFGEM (UK) also used daily data points (The Office of Gas and Electricity Markets, 2013).

4.4.6. Regression methodology

The majority of the regulators used Ordinary Least Squares regression in their estimation of the beta estimate (or the service providers on which their estimates are based used OLS estimates). The AER's (Australia) estimates of the beta were determined using Ordinary Least Squares, least absolute deviation, Theil-Sen and MM techniques (Australian Energy Regulator, 2013b).

4.4.7. Use of service provider sources

The ERO (Czech Republic) used beta estimates as estimated by a service provider (Reuters) (Energy Regulatory Office, 2009). LEWA (Lesotho) requires that beta shall be estimated using either comparator estimates, or based on standard published estimates from a reputable agency, based on countries of the same or similar development stage as Lesotho or from the African region (Lesotho Electricity Authority, 2012). The NZCC (New Zealand) and OFGEM (UK) obtain beta estimates from Bloomberg (Nixon, 2014; Regulation Branch Commerce Commission, 2010b). PUCO (USA) obtained its estimates from Value Line (The Staff of the Public Utilities Commission of Ohio, 2013). NERSA's (South Africa) methodology requires the beta to be obtained from an independent source. Per review of their MYPD 2 decision, NERSA (South Africa) uses Value Line (Mothiba et al., 2010; National Energy Regulator of South Africa, 2012). However, for MYPD 3 NERSA (South Africa) used raw beta estimates from Bloomberg (Nkadameng, Interview).

It should be noted that the use of different service providers may result in inconsistencies between different regulator's betas. As an example, Value Line includes a Blume adjustment to its beta estimates to adjust for the tendency of beta to converge towards one as found by Blume (1971) (Cueter, 2012). As a result, the beta selected by PUCO (USA) includes a Blume adjustment. Bloomberg also discloses a "raw" and "adjusted" (Blume adjusted) beta estimate. The NZCC (New Zealand) and NERSA (South Africa) selected an "unadjusted" beta while OFGEM (UK) did not disclose its selection (Nkadameng, Interview; Nixon, 2014; Regulation Branch Commerce Commission, 2010b). Regulators should ensure that they are aware of the nature of the beta which they are obtaining from the service provider, as it may result in inconsistent or inappropriate estimates of the cost of equity.

4.4.8. Blume or Vasicek adjustment applied

UREGNI (Northern Ireland), the UKCC (UK), ANEEL (Brazil), NERSA (South Africa), the NZCC (New Zealand), LEWA (Lesotho) and the ERO (Czech Republic) did not apply the Vasicek or Blume adjustment or did not include it in their guidelines for the calculation of the beta (Carvalho & Gabardo, 2013; Competition Commission, 2014b; Energy Regulatory Office, 2009; Lesotho Electricity Authority, 2012; Nkadimeng, Interview; UREGNI, 2012b). The NZCC (New Zealand) noted that the Blume and Vasicek adjustments relate to the tendencies of the equity beta, and say nothing about the tendencies of the asset beta. They note that reasons given by interested parties for Blume or Vasicek adjustments can be explained by a range of factors other than tendencies of the asset beta (Regulation Branch Commerce Commission, 2010b).

The AER (Australia) used a range of empirical estimates of the equity beta, from a number of sources. Of the sources used, only one used a Vasicek adjustment to the beta. The AER (Australia) noted that the Vasicek adjustment only resulted in a small adjustment of 0.03 for the comparator set. The AER (Australia) conceded that it has only been able to give limited consideration to the use of adjusted betas and will consider them further in future (Australian Energy Regulator, 2013b). Mr Nkadimeng (Interview) conceded that the use of a Blume or Vasicek adjustment was an item for further by NERSA (South Africa) consideration in future.

The UKCC (UK) did not see any merit of Blume or Vasicek adjustments for regulated utilities as their beta is expected to remain relatively stable and to be below one. They calculated two-year rolling betas over a ten year period and did not identify any propensity for the estimate to tend towards one. The UKCC (UK) note that they would accept a Vasicek (or Bayesian) adjustment to beta if they were assessing the beta of an individual listed company. However, they are calculating the beta of a portfolio of companies to apply to an individual unlisted company and as a result saw no role for the Vasicek adjustment (Competition Commission, 2014b).

Although PUCO (USA) did not explicitly apply the Blume adjustment, the Value Line methodology (the service provider used by PUCO (USA)), notes that it adjusts beta as recommended by Blume (1971) (Cueter, 2012). As a result, it appears that PUCO (USA) uses Blume adjusted betas.

4.4.9. Selection of comparators for beta

A common problem identified in determining the beta of a utility is the fact that there are often either few or no locally listed regulated firms. As a result of this, regulators need to consider regulated firms in other countries to be used as a proxy.

PUCO (USA) and OFGEM (UK) solely considered the beta estimates of locally listed entities. AER (Australia) also based its decision on locally listed entities, however it also did use international comparators to inform the selection of the point estimate from its range (Australian Energy Regulator, 2013b; The Office of Gas and Electricity Markets, 2013; The Staff of the Public Utilities Commission of Ohio, 2013).

NERSA (South Africa), the AER (Australia), the NZCC (New Zealand) and ANEEL (Brazil) used beta estimates of American utility companies (Carvalho & Gabardo, 2013; National Energy Regulator of South Africa, 2013). The AER (Australia), the ERO (Czech Republic) and the NZCC (New Zealand) also consider equity beta estimates from UK companies (Australian Energy Regulator, 2013b). NERSA (South Africa) and the ERO (Czech Republic) calculates beta estimates of listed European companies (Energy Regulatory Office, 2009). The NZCC (New Zealand) also considered listed Australian entities (Regulation Branch Commerce Commission, 2010b). NERSA (South Africa) also considered regulators from Latin America and the Caribbean (Nkadimeng, Interview). American and European utilities were therefore the most used in the regulators estimations. However, it should be noted that this is primarily due to the quantity of listed regulated entities in the USA.

The AER (Australia) considered the use of international comparator companies in their evaluation of the equity beta. They note that international companies do not meet the requirements of a pure-play Australian benchmark entity and should therefore not be used as the primary measure of the equity beta estimate. This is due to the fact that differences between the regulatory environment, the geography, business cycles, weather and other factors are likely to result in differences in equity beta estimates for similar companies across countries. Furthermore, these beta estimates will be measured against the foreign market portfolio, which will provide beta estimates which are not a measure of a firm's systematic risk versus the Australian market portfolio. The AER (Australia) note that the major reason regulators use international proxies is due to a lack of locally listed regulated entities. They deem the nine listed Australian companies provide sufficient evidence of the beta estimate (Australian Energy Regulator, 2013b)

ANEEL (Brazil) calculated its equity beta estimate based on US comparator companies. This was due to the fact that it had calculated an American risk free rate and equity risk premium. Also, the US market has other advantages including a large number of listed companies, transparency, liquidity and volume of information. ANEEL (Brazil) evaluated the listed energy companies to find companies that were involved in electricity transmission based on the percentage of transmission and distribution assets of total assets (with a minimum percentage of 50% required). Shares were excluded if they were not sufficiently liquid or not listed. This resulted in a sample of 15 firms (Carvalho & Gabardo, 2013).

The ERO (Czech Republic) noted that as there are no listed regulated companies in Czech Republic, international comparators were required to be used. The ERO (Czech Republic) therefore selected European comparator companies, based on the requirement that their core business is subject to regulation (Energy Regulatory Office, 2009).

Per the reasons for decision for MYPD 2, NERSA (South Africa) used six comparator companies listed on the NYSE from the USA (Mothiba et al., 2010). NERSA's (South Africa) cost of equity capital methodology requires that the beta estimate be based on a range of international companies of comparable business risk. The methodology specifies that the beta should be based on a selection of six companies, the origin of which was not disclosed (National Energy Regulator of South Africa, 2012). Mr Nkadameng (Interview) stated that NERSA (South Africa) included listed regulated utilities from North America, Western Europe, the Caribbean and Latin America in the MYPD 3. Proxies were selected on the basis of their comparability with Eskom's business risk.

The NZCC (New Zealand) notes that in New Zealand, there are very few comparable firms (in electricity transmission there is one single monopoly supplier for the entire country). As a result, it is necessary to include comparable firms (may be firms from the same service or from a service with a similar risk profile) from overseas in the sample. The sample used includes two New Zealand listed electricity distribution business as well as 52 international comparators from the UK, Australia and the US that are classified as integrated energy utilities. The sample included electricity and gas utilities as these are deemed to be of similar risk (Regulation Branch Commerce Commission, 2010b).

Although the methodologies reviewed were for electricity utilities, the ERO (Czech Republic), the OEB (Canada), PUCO (USA) and the NZCC (New Zealand) considered that it was sufficient to include both gas and electricity network entities in the comparator set. This is due to the fact that they believe that gas and electricity network entities face similar risks and therefore their betas should be comparable (Energy Regulatory Office, 2009; Ontario Energy Board, 2009; Regulation Branch Commerce Commission, 2010b; The Staff of the Public Utilities Commission of Ohio, 2013). This agrees with the findings of Schaeffler and Weber (2011).

UREGNI's (Northern Ireland) beta was calculated based on pure-play networked companies with a UK stock market listing. These comparators were not limited to purely electricity companies but also included water network companies (First Economics, 2011). The UKCC's (UK) selection of comparator companies included regulated energy and water companies in the UK, as they deem the regulatory system to be similar to that of the UK electricity companies (Competition Commission, 2014b). AER (Australia) and OFGEM (UK)

also considered regulated water entities as they deem them to be of similar risk (Australian Energy Regulator, 2013b; The Office of Gas and Electricity Markets, 2013). This is in contrast to Schaeffler and Weber's (2011) findings, as they find that water utilities have lower betas. They do note that their study is affected by a low sample size.

4.4.10. Estimate divisional betas

OFGEM (UK), the AER (Australia), the NZCC (New Zealand), the ERO (Czech Republic) and ANEEL (Brazil) selected comparators based on their core activities being subject to regulation, but did not calculate divisional betas (Energy Regulatory Office, 2009; Regulation Branch Commerce Commission, 2010b; The Office of Gas and Electricity Markets, 2013). The AER (Australia) noted that the comparator companies selected did also provide non-regulated electricity or gas services. They evaluated the extent of these non-regulated activities and concluded the impact on the beta would be sufficiently minor for the comparators to be reasonable. The AER (Australia) did exclude a comparator for the period subsequent to it changing its operations to increase the proportion of non-regulated activities (Australian Energy Regulator, 2013b).

The NZCC (New Zealand) considered that it may be necessary to make adjustments to betas for multi-divisional firms. As the beta can be seen as the weighted average of the betas of all of its divisions, it may be necessary to extract an estimate of beta for a specific type of regulated service from the overall group beta where multi-division firms are included in the comparator set. The NZCC (New Zealand) considered the use of the "pure-play" approach, the full information approach and econometric prediction based on risk drivers. However, the NZCC (New Zealand) concluded that sufficient information does not exist for these methods. The NZCC (New Zealand) also considers that it may not be necessary as some of the other divisions are likely to be of similar systematic risk (Regulation Branch Commerce Commission, 2010a).

4.4.11. Method used to un-lever and re-lever the beta

Table 9: Formula used to un-lever and re-lever the beta		
Regulator	Model	Formula
ERO (Czech Republic)	Hamada formula	$\beta_e = \beta_a [1 + (1 - T) \left(\frac{D}{E}\right)]$
AER (Australia)	Brealey-Myers formula	$\beta_e = \beta_a [1 + \left(\frac{D}{E}\right)]^{14}$
ANEEL (Brazil)		$\beta_e = \beta_a \times \left(\frac{E+D(1-T)}{E}\right)$
NERSA (South Africa)	Harris-Pringle formula	$\beta_e = \beta_a \times \left(1 + \frac{D}{E}\right)$
NZCC (New Zealand)	Tax-neutral formula ¹⁵	$\beta_e = \beta_a + (\beta_a - \beta_d) \times \frac{L}{(1 - L)}$
OFGEM (UK)		$\beta_e = \beta_a + (\beta_a - \beta_d) \times \frac{L}{(1 - L)}^{16}$
UKCC ¹⁷ (UK)		
UREGNI (Northern Ireland)	Miller formula	$\beta_a = \beta_e \times (1 - g) + \beta_d \times (g)$
ECB (Namibia)	Harris-Pringle formula	$\beta_e = \beta_a \times \left(1 + \frac{D}{E}\right)$
CERC (India)	Not applicable	
NERC (Nigeria)	Not applicable	

¹⁴ This formula can be shown to be equivalent to the Harris-Pringle (1985) formula as used by the NZCC (New Zealand), if the debt beta is assumed to be zero

¹⁵ This formula is equivalent to the Harris-Pringle (1985) formula. It was derived by the NZCC (New Zealand) by removing the tax parameter from the Miles-Ezzell formula (Regulation Branch Commerce Commission, 2010b)

¹⁶ Derived the formula used to calculate the equity beta based on the estimates for the asset beta, gearing and the equity beta

¹⁷ The UKCC (UK) did not disclose the formula used to un-lever and re-lever the beta estimates, however based on the inputs and the equity beta disclosed it would appear that the Harris-Pringle formula was used

PUCO (USA)	Not applicable
OEB (Canada)	Not disclosed
LEWA (Lesotho)	Not disclosed

Where β_a is the un-levered asset beta, β_e is the equity beta, β_d is the debt beta, D is the value of debt, E is the value of equity, L is the leverage, g is the gearing and T is the rate of tax.

PUCO (USA) did not un-lever and re-lever the beta estimates of the comparable firms used (The Staff of the Public Utilities Commission of Ohio, 2013). CERC (India) did not rely on the CAPM and therefore it did not consider a model for un-levering and re-levering the beta estimate (Central Electricity Regulatory Commission, 2009). The OEB (Canada) relied on the cost of equity calculations of a range of submissions in its decision on the ROE. It therefore did not disclose a formula to un-lever and re-lever the beta (Ontario Energy Board, 2009).

The AER (Australia), ANEEL (Brazil), the ECB (Namibia), NERSA (South Africa) and the ERO (Czech Republic) did not disclose their reasoning behind the debt beta, however based on the formulas used, they implicitly assume a debt beta of zero in their formula (Electricity Control Board, 2001; Energy Regulatory Office, 2009; National Energy Regulator of South Africa, 2013). Submissions to the AER (Australia) noted that financial leverage has relatively little effect on the overall equity beta, and therefore recommended that the AER (Australia) estimates the equity beta without de-levering and re-levering the comparator betas. The AER (Australia) concluded that although the effect may be small because the industry average gearing approximated the benchmark efficient companies gearing, the difference may be greater for individual firms (Australian Energy Regulator, 2013b). The AER (Australia) therefore decided to de-lever and re-lever the comparator set of companies' betas.

Although the NZCC (New Zealand) chooses a model which includes a debt beta term, it assumes a debt beta of zero in its methodology. This was due to the practical difficulties implicit in estimating the debt beta. It notes that this is a conservative estimate in favour of regulated suppliers (Regulation Branch Commerce Commission, 2010b).

OFGEM (UK) assumes a debt beta of 0.1 in its estimation of the equity beta, based on the Harris-Pringle formula. UREGNI (Northern Ireland) assumed a debt beta of 0.1 for Northern Ireland Ltd, however, in its determination of the appeal, the UKCC (UK) assumed the debt beta to be 0.05, however it did note that results do not tend to be sensitive to the debt beta

(Competition Commission, 2014b; The Office of Gas and Electricity Markets, 2013; UREGNI, 2012b).

NERSA (South Africa) chooses the Harris-Pringle formula based on an evaluation of the tax treatment of the NERSA (South Africa) regulatory methodology and per consideration of international regulators' decisions (Nkadimeng, Interview).

The NZCC (New Zealand) discussed the merits of the Hamada model (which it had used in previous regulatory determinations) and the tax neutral formula (which they state is equivalent to the Miles-Ezzell formula without taxes). The previous use of the Hamada model was based on the differences between taxes between New Zealand and the overseas countries. The NZCC (New Zealand) now considers that the use of a model without a tax term is more appropriate as the use of a tax term assumes a classical tax regime and that debt (as opposed to leverage) is fixed in dollar terms. The NZCC (New Zealand) believes that the assumption that leverage is fixed is a better assumption, which leads to the Miles-Ezzell formula without a tax term (which is equivalent to the Harris-Pringle formula) (Regulation Branch Commerce Commission, 2010b).

There therefore appears to be a preference for the Harris-Pringle formula by the Regulators included in the survey and for the use of a debt beta of zero.

4.4.12. Black CAPM

The AER (Australia) notes the tendency of the Sharpe-Lintner CAPM to understate the cost of equity for low beta stocks and to overstate the cost of equity for high beta stocks. The AER (Australia) therefore uses the Black CAPM in an attempt to inform its estimate of the beta. It's discussion of the use of the Black CAPM as the model to estimate the cost of equity was discussed in section 4.1.4. The AER (Australia) notes that while the Black CAPM does indicate towards the selection of a higher estimate of beta, the extent of the adjustment is not easy to ascertain (Australian Energy Regulator, 2013b).

4.4.13. Other regulatory decisions

The ERO (Czech Republic) and the NZCC (New Zealand) considered the beta estimates as determined by a range of European energy regulators in their determinations (Energy Regulatory Office, 2009; Regulation Branch Commerce Commission, 2010b). NERSA (South Africa) considered the determinations of the AER (Australia) in its MYPD2 (Mothiba et al., 2010). UREGNI (Northern Ireland) considered other regulatory decisions from a range of UK regulators across water, rail, aviation, telecoms, railway and energy (First Economics, 2011). The AER (Australia) considered the studies on beta as prepared by the Economic Regulation Authority of Western Australia. The AER (Australia) had previously considered

using decisions on regulated water networks as a cross check, as these are deemed to face comparable systematic risk. However, this was deemed to have little informational impact as the Australian regulators base their estimates on Australian energy regulators decisions (Australian Energy Regulator, 2013b).

4.4.14. Summary of the equity beta section

Based on the regulators surveyed, there was a preference to estimate betas using empirical analysis, on the assumption that the historically observed beta is a good estimator of the future beta. However, there was no consensus identified in the methods used to estimate the beta.

In spite of the lack of agreement, NERSA's (South Africa) selection of estimation periods, number of data points, lack of Blume or Vasicek adjustment and levering and unlevering formula did correspond with other regulators. As there is little agreement among regulators, points of difference between NERSA (South Africa) and other regulators are to be expected. In comparison to the other regulators reviewed, NERSA (South Africa) selected proxy companies from a wider range of different countries and regulatory environments, which may allocate the risk differently between the regulated firm. As a result, Eskom may not be appropriately compensated for risk due to the differences in the nature of the entities (such as Eskom's predominantly aging coal-fired electricity generation infrastructure), different regulatory environments (Eskom's price determinations last for five years), weather patterns and business cycles. Therefore the proxy betas may understate (overstate) Eskom's actual beta and result in the cost of equity allowed being understated (overstated). However, it should be noted that no regulators included in the survey made adjustments for these factors, aside from the AER who chose not to use US utilities due to the availability of locally listed firms.

The AER (Australia) was the only regulator to use the Black CAPM to adjust for the CAPM's propensity to understate the cost of equity of low beta stocks. It therefore appears that regulators, including NERSA (South Africa), are not adequately compensating regulated firms in the calculated cost of equity. Also, none of the regulators surveyed adjusted the beta estimates using the Blume or Vasicek adjustments. Although it must be noted that PUCO (USA) used betas as estimated by Value Line, which adjusts its betas using a Blume adjustment.

5. Summary

5.1. Conclusion

This study was performed in order to investigate the methodologies employed by electricity regulators to determine the cost of equity capital of a regulated firm. Given the importance of the cost of equity capital on the tariff determination, particularly in a South African environment, the study further aimed to determine whether NERSA's methodology is in line with international best practice. The study aimed to answer the following research questions:

Research question 1: How is the cost of equity estimated in a regulatory environment?

Research question 2: Is NERSA's (South Africa) cost of equity methodology consistent with international practice?

The main empirical findings of this study were summarised in each section in Chapter 4: Regulatory Survey. This section summarises the research findings in relation to the study's two research questions.

Research question 1: How is the cost of equity estimated in a regulatory environment?

The review of literature showed little consensus among academics as to the selection of cost of equity model and its determinants, generally and more specifically within a regulatory environment. Empirical studies have found that the CAPM tends to understate the allowed return on low beta firms, such as utilities. In a tariff determination, this would result in the tariffs being understated and regulated firms not being appropriately compensated for the risk taken. Furthermore, empirical studies have found that the APT model and the FF3F model both result in higher estimates of the cost of equity than the CAPM, with the FF3F having better explanatory power than both models.

The survey on the regulators' methodologies found an overwhelming preference for the use of the CAPM. 12 of the 14 regulators surveyed used the CAPM as their primary model or considered it as a secondary model. This agrees with the findings of Schaeffler and Weber (2011). Regulators prefer this model due to its appealing theory, its relative transparency and its widespread use in regulatory decisions. Very few of the regulators considered that the CAPM understates the cost of equity for low beta firms, and only the AER (Australia) considered using alternatives (such as the Black CAPM) to account for this propensity.

Furthermore, although the FF3F was considered by certain of the regulators, it is interesting to note that in spite of empirical studies showing that it should be considered by regulators (see Chrétien and Coggins (2011) and Schaeffler and Weber (2011)), no regulators chose to use this model. This was primarily due to its complexity to implement and lack of widespread use.

Beyond the use of the CAPM, very little consistency was found among regulators in terms of the methods used to calculate the inputs. This is due in part to different economic environments in each country as markets with low liquidity in the financial markets, as an example, may be unable to determine sufficiently reliable estimates. However it is also a result of the lack of consensus in financial theory.

This lack of consensus as to the appropriate cost of equity methodology to be used by the regulator results in judgement needing to be applied by regulators. Until academic theory and empirical studies agree on the appropriate cost of equity model to apply, it is likely that this debate will rage on amongst regulators. As changes to the methodology are likely to result in increased regulatory risk, regulators will continue to use the CAPM to maintain consistency and transparency between regulatory determinations.

Research question 2: Is NERSA's (South Africa) cost of equity capital methodology consistent with international practice?

Given the lack of agreement among academics and regulators, differences among regulatory methodologies will be common. As a result, while there are differences between NERSA's (South Africa) methodology and international regulators, these are due to a wide range of options selected by regulators. The major differences identified by the survey relate to the method of averaging selecting to calculate the ERP, as well as the process, and the lack of transparency thereof, followed by NERSA (South Africa) to calculate the cost of equity.

NERSA (South Africa) did not appear to consider the use of alternative cost of equity models than the CAPM. However, this is in line with the regulators surveyed, as 12 of the 14 regulators used the CAPM.

A key finding of the survey is the lack of consideration of alternative methods or models by NERSA (South Africa). Regulators in developing economies, such as the US, Australia, New Zealand and the United Kingdom considered a number of alternative methodologies in assessing the model to use and the inputs therein. These were then used to inform the estimates made, allowing for increased reliability and reasonability of the estimates. This increases the transparency of the regulatory process. It should be noted that this may be a result of a lack of resources on the part of NERSA (South Africa) and may also result to lack of available data (such as to apply the FF3F). Mr. Nkadameng (Interview) noted that all of the models have some shortcomings, and that the selection of the CAPM is due to its widespread use among regulators.

NERSA's (South Africa) selection of the geometric method of averaging in the estimation of the ERP is not in line with international practice, as a preference for the arithmetic method was identified. This results in the calculated ERP being up to 2% lower than that calculated using the arithmetic method. This has a direct effect of decreasing the cost of equity calculated in the tariff determination. However, Damodaran (2010) recommends the use of a geometric mean when considering a longer term horizon. NERSA's (South Africa) approach therefore does have a theoretical foundation. In contrast, studies by Blume (1974) and Indro and Lee (1997) indicate that a weighted average of the two methods is most appropriate, indicating that the arithmetic average would overstate the return. Regulators such as the AER (Australia), OFGEM (UK) and the UKCC (UK) did consider both geometric and arithmetic averages or used a weighted average.

Transparency in the regulatory process, as well as consistency among regulatory periods, are key elements to an effective methodology. This will allow for regulated entities to plan, and reduces the costs associated with unexpected outcomes. Furthermore, given the emotive nature of the electricity tariff increases, this would also reduce the risk of political engineering. NERSA's (South Africa) disclosure of the calculated tariffs for the MYPD 3 period did not show the calculation of the inputs (or the thought process behind such calculations) as it is against policy to disclose certain information (Nkadameng, Interview). This study found that NERSA (South Africa) used a 111 year average of the ERP (based on the Credit Suisse Research Institute's (2012) calculation), whereas NERSA's (South Africa) published methodology requires a 25 year sampling period be used. This highlights the lack of transparency of the regulatory process and therefore results in increased regulatory risk for the regulated firm.

5.2. Limitations of this study

This study evaluated the cost of equity capital methodologies of 14 electricity regulators and can therefore not be extrapolated across all electricity regulators or across regulators in different industries.

This study is limited to the information which was published by the regulators. Certain regulators, such as the AER (Australia), the NZCC (New Zealand) and OFGEM (UK), included extensive reasoning behind each decision in their estimation of the cost of capital. Other regulators, such as NERSA (South Africa), provided limited explanations for their cost of equity methodology. The result of this is that this study may be biased towards the methodologies elected by the regulators with more extensive disclosure.

These limitations mentioned do not invalidate the findings of this study to the point where this study may not be relied upon. The regulators selected were from 13 different countries across six continents. These regulators operated in developed and developing economies.

5.3. Recommendations for further research

A number of areas for further research have been identified that relate closely to the topic of this paper and are discussed in this section.

This study focussed on the cost of equity capital in electricity regulator decisions. Further research could extend this study to include other industries, such as water, airports, gas and railways.

This study focussed on the cost of equity capital in a regulatory environment. This is primarily due to the breadth of this subject as well as the fact that the cost of equity is the most subjective element of the cost of capital decision. A natural extension of this topic would be to perform a study on the cost of debt or to assess the methods used to determine the cost of capital.

Also, the cost of capital cannot be considered in isolation in a regulatory determination. Regulators make decisions based on the regulatory environment in which they operate. This may relate to the treatment of tax or inflation in the cost of capital. For example, a real cost of capital may be used if the regulatory asset base is based on the depreciated replacement cost of the asset. Further research could extend this study to evaluate the impact of the regulatory treatment of the cash flows on the cost of capital.

The cost of equity capital is a key element in the determination of regulated companies allowed tariff increases. As these regulated entities by their nature are structurally important to the economy, changes in the cost of equity capital can have a large impact on the economy as a whole. Future research could focus on the impact of the cost of equity capital on the economy as a whole, through variables such as GDP growth, unemployment and inflation.

The selection of an appropriate cost of equity model can have a large effect on the outcome of the regulatory determination. Given the lack of consensus of appropriate cost of equity models to use in regulation, with the CAPM empirically found to understate the required returns of low beta stocks, future research could be used to estimate the cost of equity for regulators (focussing specifically on Eskom) using different models. The aim would be to determine which model yields a cost of equity closest to historically realised rates.

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7. Appendices

7.1. Appendix A: AER (Australia) requirements for a model

The AER (Australia) has developed a set of criteria with which to use to assess the models and assumptions used in calculating the cost of capital (Australian Energy Regulator, 2013a). The criteria are that the models, market data, methods, and other evidence must be:

1. Consistent with well accepted economic and financial theory and must be supported by robust data.
2. Fit for purpose,
 - a. i.e. consistent with the purpose for which it was compiled and the limitations thereof
 - b. Promote simple over complex approaches where appropriate
3. Implemented in line with good practice
 - a. I.e. supported by robust, transparent and replicable analysis based on data obtained from credible sources.
4. Models for return on equity and debt must be
 - a. based on quantitative modelling that is sufficiently robust that they aren't too sensitive to errors in input estimation
 - b. based on quantitative modelling which avoids filtering or adjustment of data that does not have a sound rationale
5. Market data or information used must be credible, verifiable, comparable, timely and clearly sourced.
6. Sufficiently flexible to allow for changes in market conditions to be reflected in regulatory decisions

7.2. Appendix B: Description of regulators

7.2.1. Agência Nacional de Energia Elétrica (ANEEL)

ANEEL (Brazil) is the electricity regulator in Brazil. ANEEL (Brazil) was created by Law no. 9,427 from December 26, 1996 and regulated by Decree np. 2,335 from October 6, 1997. ANEEL (Brazil) is responsible for determining the regulated electricity tariff, ensuring that a balance is maintained between the economic and financial impact of the tariff. ANEEL (Brazil) uses a revenue cap method. Brazil's regulated electricity industry is currently in its Third Revision Cycle Period (3CRP-T) which runs for five years from July 2013 until July 2018 (Caldwell & Gabardo, 2013).

7.2.2. Australian Energy Regulator (AER)

The AER (Australia) regulates energy markets and networks mainly in Eastern and Southern Australia. This includes the process of setting the prices charged for using energy networks to transport energy to end users (AER, 2013a). The AER (Australia) applies the regulatory framework for electricity networks as set out in the National Electricity Law and Rules Chapter 6 and 6A (AEMC, 2014; AER, 2013b). Regulated entities must apply to the AER (Australia) to determine their revenue requirements on a five year basis. The AER (Australia) evaluates these applications based on the requirements of the National Electricity Rules. The AER (Australia) is required to set a maximum allowable revenue or price for the electricity network based on the National Electricity Rules (AEMC, 2014; AER, 2013b). The AER (Australia) publish a set of guidelines for every five year period showing the inputs that are required to be used for the regulated networks applications over the next five year period (AER, 2009).

7.2.3. Central Electricity Regulatory Commission (CERC)

CERC (India) is the electricity regulator in India. It is responsible for determining electricity tariffs and for the formulation of the National Electricity Policy and Tariff Policy in terms of the Electricity Act of 2003 (CERC, 2014). CERC (India) issues the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, which last for a five year period. The current period lasts from 01/04/2014 until 31/03/2019. CERC (India) follows an administrative process for the determination of the tariff methodology, allowing comment by interested parties (Central Electricity Regulatory Commission, 2014).

7.2.4. Commerce Commission (NZCC)

The NZCC (New Zealand) is New Zealand's competition enforcement and regulatory agency (Commerce Commission, 2014). This includes the regulation of electricity line services and gas pipeline services under Part 4 of the Commerce Act (1986). This requires the NZCC (New Zealand) to regulate the price and quality of goods or services in markets where there is little or no competition (Regulation Branch Commerce Commission, 2010a). The NZCC (New Zealand) determines the input methodologies in order to promote certainty for the regulatory entities as well as customers. Regulated companies are subject to default/customised price-quality regulations, which last for a five year period. These regulations either limit the revenue an entity may earn or set the maximum prices which the entity may charge, as well as setting the minimum service quality standards. This is a "CPI-X" form of regulation where prices are allowed to increase each year at a maximum of the rate of inflation, less adjustments for productivity improvements (Commerce Commission, 2012).

7.2.5. Competition Commission (UKCC)

The UKCC (UK) closed down on 1 April 2014 and its functions were transferred to the Competition and Markets Authority. Prior to that date, the UKCC (UK) was an independent body, with the aim of ensuring healthy competition between companies in the UK with the ultimate benefit of the consumers and the economy. This responsibility includes considering disputes concerning proposed regulatory changes, include changes to price controls. The UKCC (UK) is therefore not a regulator, but is responsible for determining regulatory references and appeals (Competition Commission, 2014a). UREGNI's (Northern Ireland) RP5 determination was referred to the UKCC (UK), as NIE Ltd did not accept the proposed price controls. The UKCC's (UK) determination is therefore subject to the regulatory environment in Northern Ireland (Lynch, 2013).

7.2.6. Electricity Control Board (ECB)

The ECB (Namibia) is tasked with regulating the electricity supply industry in Namibia in terms of the Electricity Act of 2007. This includes regulating tariffs to ensure that they are cost reflective and are based on sound economic principles. The regulatory methodology is based on rate of return regulation (Electricity Control Board, 2001). The tariff period in Namibia is for one year, with Nampower applying for an increase annually. The ECB (Namibia) is responsible for evaluating the application and determining the allowable increase. The current period lasts from 01 July 2014 until 31 June 2015 (Electricity Control Board, 2014).

7.2.7. Energy Regulatory Office (ERO)

The ERO (Czech Republic) is the regulator of the energy sector in the Czech Republic. The ERO (Czech Republic) sets out the method of regulation of energy industries and the price control procedures as required by the Act No. 458/2000 on the Conditions of Business and State Administration in Energy Industries and on Changes to Certain Laws. The regulatory period in the Czech Republic lasts for five years, with the current Regulatory Period III lasting between 2010 and 2015. The ERO (Czech Republic) follows an administrative process in the determination of the tariff methodology, using a consultation process to enable stakeholders to argue the merits of certain regulatory decisions. The ERO (Czech Republic) uses a revenue cap regulatory method, with costs subsequently being increased using an escalation factor (Energy Regulatory Office, 2009).

7.2.8. Lesotho Electricity and Water Authority (LEWA)

LEWA (Lesotho) (previously the Lesotho Electricity Authority), is responsible for regulating the electricity, water and sewerage services in Lesotho. This regulation is performed in accordance with the requirements of the LEA Act of 2002. LEWA (Lesotho) released their methodologies for the charging principles for electricity, water and sewerage services in 2012. This provides a guide for licensees to be used in their tariff applications (Lesotho Electricity Authority, 2012). Regulated companies are required to make Tariff Review Applications to LEWA (Lesotho), which occurs on an annual basis. The tariffs are adjusted on an administrative basis subject to consultation with stakeholders (Lesotho Electricity and Water Authority, 2013).

7.2.9. National Energy Regulator of South Africa (NERSA)

NERSA (South Africa) is a South African national energy regulator with the mandate to regulate the electricity, piped-gas and petroleum industries. Electricity is regulated in terms of the Electricity Regulation Act (Act No.4 of 2006) (NERSA, 2009). NERSA (South Africa) regulates the electricity industry based on a methodology that incorporates rate of return as well as incentive based principles. This methodology states that the revenue to be earned by Eskom should be equal to the efficient cost to supply electricity plus a fair return on the rate base (National Energy Regulator of South Africa, 2012). Eskom's revenue is determined by Multi-Year Price Determinations (MYPD), the current being MYPD 3 which lasts from 1 April 2013 to 31 March 2018 (National Energy Regulator of South Africa, 2013). Prior to each MYPD, NERSA (South Africa) re-evaluates its methodology for calculating the components of the allowable revenue, to ensure that it meets the requirements of the MYPD objectives (National Energy Regulator of South Africa, 2012; Nkadimeng, Interview).

NERSA (South Africa) follows an administrative based method of setting the cost of capital where NERSA (South Africa) initially publishes its methodology, and allows Eskom and the public to comment on the components of the allowable revenue. NERSA (South Africa), taking this into account, publishes the Decision on the allowable revenue for Eskom (National Energy Regulator of South Africa, 2013).

7.2.10. Nigerian Electricity and Regulatory Commission (NERC)

NERC (Nigeria) is Nigeria's independent energy regulatory authority and is established in terms of the Electric Power Sector Reform Act of 2005. NERC (Nigeria) regulates the Nigerian energy supply industry, of which one of its functions includes determining tariffs. NERC (Nigeria) introduced a Multi-Year Tariff Order in 2008 (MYTO I). This provided for a 15 year tariff path, of which minor reviews would occur bi-annually and a major review would occur every five years. MYTO II is currently in place and lasts from 1 June 2012 to 31 May 2017 and uses a building blocks approach for the calculation of regulated prices (Nigerian Electricity and Regulatory Commission, 2012).

7.2.11. The Northern Ireland Authority for Utility Regulation (UREGNI)

UREGNI (Northern Ireland) is the regulator for the gas, water and electricity generation, transmission and supply industries in Northern Ireland. UREGNI's (Northern Ireland) principal statutory objective is to protect the interests of the electricity consumers under the Electricity (Northern Ireland) Order 1992 ("The Order"). UREGNI (Northern Ireland) issued the fifth price control (RP5) relating to Northern Ireland Electricity Ltd (NIE Ltd), a monopoly firm involved in the distribution and transmission of electricity (UREGNI, 2012a). RP5 is for a five year period from 2012 until 2017 and is based on a revenue cap method (Competition Commission, 2014b).

The Order includes the requirement that UREGNI (Northern Ireland) may not make the price control modification unless NIE Ltd consents to it. NIE did not consent to the RP5 determination, and as a result, UREGNI (Northern Ireland) required the UKCC (UK) to investigate and report on the determination (Lynch, 2013).

7.2.12. The Office of the Gas and Electricity Markets (OFGEM)

OFGEM (UK) regulates gas and electricity companies across the UK excluding Northern Ireland. Its powers are provided for under the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998 and the Enterprise Act 2002 (OFGEM, 2014c; Sudarsanam et al., 2011). OFGEM's (UK) current price control, named DCRP5, runs from 1 April 2010 to 31 March 2015 is based on the RPI-X regime. OFGEM (UK) recently launched its RIIO-ED1 price control review for the period starting 1 April 2015 and will last for eight years (OFGEM, 2014a, 2014b). The price control sets a total revenue allowance and places incentives for operators to innovate and find efficiencies in the way that they provide the service (OFGEM, 2014b; Sudarsanam et al., 2011).

7.2.13. Ontario Energy Board (OEB)

The OEB (Canada) is responsible for regulating the natural gas utilities and electricity utilities in Ontario. Its duties are performed in terms of the Ontario Energy Act of 1998 and the Electricity Act of 1998. The OEB (Canada) determines the cost of capital based on the requirements of the Fair Return Standard (FRS). The FRS has three standards; the comparable investment standard, the financial integrity standard and the capital attraction standard. This standard is therefore sufficiently broad to allow the OEB (Canada) to exercise judgement in the setting of the cost of capital methodology (Sudarsanam et al., 2011). The OEB (Canada) updated their approach to estimating the cost of capital in 2009. Rate applications are set individually on a case by case basis, following a semi-judicial process. The OEB (Canada) panels which consider rate applications are not restricted by the cost of capital methodology, and may deviate from its requirements in specific circumstances (Ontario Energy Board, 2009).

7.2.14. Public Utilities Commission of Ohio (PUCO)

PUCO (USA) is a US state regulator that regulates electric, natural gas, telecommunications, water, waste and transport companies in Ohio (The Public Utilities Commission of Ohio, 2014a). The tariff period lasts for one year although in practice it lasts until the next rate case (Sudarsanam et al., 2011). PUCO (USA) follows a judicial based process for determining the tariffs for utilities under regulation. Stakeholders may file an application for a tariff increase with PUCO (USA), dubbed a "rate case", which are normally brought by the regulated company. The rules for setting the tariff are based on the laws passed by the state legislature as well as case law based on prior decisions by the Ohio Supreme Court. Parties may appeal PUCO (USA) decisions to the Ohio Supreme Court (The Public Utilities Commission of Ohio, 2014b).